TUNDRA OIL & GAS

PROPOSED DALY UNIT NO. 18

Application for Enhanced Oil Recovery (EOR) Project and Voluntary Unitization

Bakken Formation

Bakken-Torquay A Pool (01-62A)

Daly Area, Manitoba

This application includes forward looking statements. Statements other than statements of historical fact are forward-looking statements. Words such as “believe”, “will”, “may”, “may have”, “would”, “estimate”, “continues”, “anticipates”, “intends”, “plans”, “expects”, “budget”, “scheduled”, “forecasts”, and similar words identify estimates and forward-looking statements. Forward-looking statements are not guarantees and involve known and unknown risks, and uncertainties, including, but not limited to commodity price, price of purchased goods and services, global economic situation, quantity of oil and natural gas reserves, results of waterflood, individual well results, legal, political and environmental changes which may cause the actual results to vary materially from forecast.

Author(s):

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Addressee: **Officer of the Crown**

Manitoba Government Regulatory Services (Oil and Gas)
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INTRODUCTION

Tundra Oil & Gas Ltd. (Tundra) has commissioned GLJ Ltd. (GLJ) to provide a 3rd party technical study (the GLJ Technical Study) on the proposed Daly Unit 18 application area. In their analysis, GLJ has provided best estimates of OIIP, recoverable oil volumes for both primary (existing) and waterflood development plans and expected royalty ownership information under waterflood development.

This application references results from GLJ's analysis. Please refer to the GLJ report for additional information as provided in Appendix A

Appendix A contains the GLJ Technical Study. This Application will reference where GLJ completed the unit application requirements, and Tundra will address the unit application requirements that are outside of GLJ's scope.

The Daly Sinclair Field is located in Townships 6-11 Ranges 27-29 WPM (Map 12 – "Daly Sinclair Field Boundary"). Within the Daly Sinclair Field, Bakken-Torquay A pools have been developed with the drilling of horizontal wells on primary recovery of reserves at various inter well spacings.

Potential exists for incremental reserves to be recovered through an Enhanced Oil Recovery Waterflood Scheme in the Bakken formation through unitization (referred to as "Secondary Recovery") within a project area comprised of the N $^1/_2$ of Section 32-010-28W1 (Appendix A: GLJ Technical Study for Map 1 – "Daly Units" referred to as the "Application Area").

The Application Area proposed for unitization is within the existing designated pool (Map 13 – "Bakken-Torquay A Pool Map"). Tundra is operator of the lands within the Application Area currently comprised of 2 producing horizontal wells. A well list including recent production statistics of the existing wells is attached as Appendix A: GLJ Technical Study for Table 1 – "Daly Unit 18 Well List and Status". Tundra's contemplated development includes the drilling of two additional wells with the potential of converting the two existing producing horizontal wells to water injection, subject to technical discretion of the unit operator taking into consideration factors such as production performance and associated economics among others.

Tundra seeks to initiate Secondary Recovery of the pool within the Application Area. If this application is approved by the Manitoba Petroleum Branch (the "Crown"), the proposed name for the unit would be Daly Unit No. 18.

Tundra submits this application to establish Daly Unit No. 18 and implement an Enhanced Oil Recovery (EOR) Project by way of Secondary Recovery within the Bakken formation.

SUMMARY

1. The Application Area contains 2 producing horizontal wells held by Tundra 100% of which fall fully within the proposed Application Area and produce from the Bakken formation (the "Wells"). The Application Area is situated North of Daly Unit No. 8 (Appendix A: GLJ Technical Study for Map 1 – "Daly Units").

2. OIIP for the proposed unit area was estimated using geological mapping as prepared by GLJ. OIIP was calculated by legal sub-division, on a 40 acre basis. Using the results of GLJ's geological mapping, petrophysical analysis and initial properties the OIIP for the proposed Daly 18 Unit, is 173.89 E^3m^3 (1.1 MMbbl) oil as shown in Appendix A: GLJ Technical Study for Table 2 – "Daly Unit 18 Volumetric Summary and OIIP".

3. As of June 30, 2024, cumulative production from two producing wells within Daly Unit No. 18 totaled 17.6 E^3m^3 of oil, and 30.1 E^3m^3 of water, reflecting a 10.1 percent recovery factor (RF) of the calculated OIIP. (Please refer to page 12 of Appendix A: GLJ Technical Study).

4. Expected ultimate recoverable oil volumes under primary recovery operations within the proposed Daly Unit 18 is estimated to be 19.4 E^3m^3. This represents the current development in the proposed unit area and represents 11.2 percent recovery factor of OIIP. As of July 1, 2024, the remaining recoverable volumes are estimated to be 1.8 E^3m^3. (Please refer to pages 12 – 13 of Appendix A: GLJ Technical Study).

5. Oil production within the proposed Daly 18 Unit area began in April 2014. Primary production is from two horizontal wells which achieved a combined peak oil rate of 31.55 m^3/d in November 2014. As of June 30, 2024, the wells are producing at a combined rate of 1.32 m^3/d at a 72.52 percent water cut. The wells are currently declining at a combined rate of approximately 29 percent per annum (Please refer to page 12 of a A: GLJ Technical Study).

6. The expected ultimate oil recoverable volume under waterflood operations is estimated to be 37.7 E^3m^3, with a remaining recoverable oil volume of 20.1 E^3m^3, as of July 1, 2024. Ultimate recoverable volumes represent an approximate 21.6 percent recovery factor of OIIP. An incremental 18.3 E^3m^3 of oil is projected to be recovered through secondary recovery, equivalent to 10.3 percent incremental recovery factor due to waterflooding operations (Please refer to page 15 of Appendix A: GLJ Technical Study).

7. Based on waterflood response in the adjacent units within the Daly Sinclair Field, the Three Forks and Middle Bakken Formation in the proposed Application Area are believed to be analogous and therefore suitable reservoirs for secondary recovery based on proximity.

8. The strategy for development is expected to include the drilling of additional cased hole horizontal wells in addition to converting the existing cased hole horizontal wells to injection wells within the Application Area with the goal of setting up a 200 meter line drive waterflood congruent with existing developments in the Daly Sinclair Field (Appendix C – "Horizontal Injector Downhole Diagram").

ENHANCED OIL RECOVERY (EOR) PROJECT APPLICATION

GEOLOGY

Please refer to pages 5 – 10 of Appendix A (GLJ Technical Study).

Oil Initially in Place (OIIP or OOIP in Table 5)

Please refer to pages 10 – 11 of Appendix A (GLJ Technical Study).

Historical Production:

Please refer to pages 12 – 13 of Appendix A (GLJ Technical Study).

Technical Studies:

Tundra engaged GLJ to conduct a technical study for proposed Daly Unit No. 18. In GLJ's letter to Tundra October 15, 2024 (Appendix A Page 2) the stated scope was: "… volumetric, fluid and production forecasts based on volumetric calculations using GLJ's geological mapping for the Lyleton "A" and Bakken zones. As part of the scope of work, GLJ has also prepared estimates of future production under primary and waterflood recovery, estimates of recovery factor and remaining recoverable volumes. This analysis incorporates well, core and log data available to June 30, 2024.

A brief discussion of the methodology estimates of petroleum initially-in-place and recoverable volumes as well as pore volume mapping, production forecasts and estimated tract factors are included in the attached report".

Future Unit Development Plan:

Primary recovery from existing horizontal wells in the Application Area has declined significantly from the peak rate indicating a need for additional pressure support under Secondary Recovery. To increase pressure support of the reservoir, subject to approval of this application, Tundra Intends to drill two horizontal producing wells, noted as "Producer Drill" (see Appendix A: GLJ Technical Study for Map 2 – "Proposed Daly Unit 18 Development Plan"). Tundra may further evaluate an opportunity to convert two Horizontal Wells to injection, both of which are noted as "Conversion" also in Appendix A: GLJ Technical Study for Map 2 – "Proposed Daly Unit 18 Development Plan". The drilling and injection conversions are subject to results of the waterflood and technical discretion of the unit operator taking into consideration factors such as production performance and associated economics among others.

Reserve Recovery Profile and Production Forecast:

The waterflood performance predictions for the proposed Daly Unit No. 18 is based on oil production decline curve analysis, and the Secondary Recovery predictions conducted by GLJ.

Primary recovery Production Forecast:

Please refer to pages 12 - 13 of Appendix A (GLJ Technical Study).

Timing for Conversion of Horizontal Wells to Water Injection:

Tundra anticipates converting to injection two wells within the North 1/2 of Section 32. The water injection conversion schedule for the balance of well(s) in the Application Area is subject to knowledge gained from previous conversions and results.

Criteria for Conversion to Water Injection Well:

Tundra currently anticipates converting two wells to injection within the Application Area as demonstrated in Appendix A: GLJ Technical Study for Map 2 – "Proposed Daly Unit 18 Development Plan".

To assess timing of horizontal well conversion from primary production to water injection service, Tundra will monitor the following parameters:

- Measured reservoir pressures at start of and/or through primary production
- Fluid production rates and changes in decline rate
- Any observed production interference effects with adjacent vertical and horizontal wells
- Pattern mass balance and/or oil recovery factor estimates
- Reservoir pressure relative to bubble point pressure

Monitoring these parameters will enable the proposed Daly Unit No. 18 to be developed efficiently and provide the greatest chance the waterflood will sweep oil from the reservoir with pressure support for the mutual benefit of Tundra and the mineral owners.

Secondary EOR Production Forecast:

Please refer to pages 13 – 15 of Appendix A (GLJ Technical Study).

Estimated Fracture Gradient:

Completion data from the existing producing wells within the project area indicate a fracture pressure gradient range of 16-22 kPa/m true vertical depth (TVD). Tundra expects the fracture gradient encountered during completion of the proposed horizontal injection well will be somewhat lower than these values due to expected reservoir pressure depletion.

Waterflood Operating Strategy

Water Source

Injection water for the proposed Daly Unit No. 18 is anticipated to be sourced from the 100/12-24-010-29W1/02 Jurassic water source well. Jurassic-source water can be produced from the 100/12-24-010-29W1/02 Water Source well and filtered at the 12-24-10-29 filter plant. Diagrams of the anticipated water injection system are illustrated in Appendix B – “Water Injection System” and will not involve the injection of fresh water.

Tundra does not foresee injectivity issues when using Jurassic sourced water for the waterflood operations in the proposed Daly Unit No. 18. Additional source water wells will be completed to meet voidage replacement volumes as required.

Injection Wells

The water injection wells for the proposed Daly Unit No. 18 could be re-configured for downhole injection after approval for waterflood has been received. The horizontal injection wells are anticipated to be completed with a cased hole design. An example of the downhole configuration can be seen in Appendix C – “Horizontal Injector Downhole Diagram”.

The water injection wells can be placed on injection after the approval to inject has been received from the Crown. Wellhead injection pressures should be maintained below the least value of either:

1. The area specific known and calculated fracture gradient, or
2. The licensed surface injection Maximum Operating Pressure (MOP)

Tundra has a thorough understanding of area fracture gradients. A management program will be utilized to set and routinely review injection target rates and pressures vs. surface MOP and the known area formation fracture pressures.

All new water injection wells will be surface equipped with injection volume metering. An operating procedure for monitoring water injection volumes and meter balancing can be utilized to monitor measurement of the entire system and associated integrity.

The proposed Daly Unit No. 18 horizontal water injection wells rate is forecasted to average 10 – 40 m3 WPD, based on expected reservoir permeability and pressure.

Reservoir Pressure Management during Waterflood

No initial pressure surveys are available for the proposed Daly Unit No. 18 project area in the Bakken formation. Tundra has a representative initial pressure survey available for a nearby horizontal well and it is believed the initial reservoir pressure in this area was on average ~6,000 kPa (Appendix D – "Representative Initial Pressure").

Upon injection, a 2–4-year reservoir re-pressurization period due to cumulative primary production voidage and pressure depletion is possible, but it could be longer or shorter. Initial monthly Voidage Replacement Ratio (VRR) is expected to be approximately 1.2 to 2.0 within the unit during the re-pressurization period. As the cumulative VRR approaches 1.0, target reservoir operating pressure for waterflood operations is forecasted to be 75-90% of original reservoir pressure.

Waterflood Surveillance and Optimization

EOR response and waterflood surveillance within the Application Area will consist of the following:

- Regular production well rate and watercut testing
- Daily water injection rate and pressure monitoring vs target rates
- Water injection rate/pressure/time vs. cumulative injection plot
- Reservoir pressure surveys as required to establish pressure trends
- Pattern VRR
- Potential use of chemical tracers to track water injector/producer responses
- Use of some or all of: Water Oil Ratio (WOR) trends, Log WOR vs Cum Oil, Hydrocarbon Pore Volumes Injected, Conformance Plots

The above surveillance methods should contribute to an ever-increasing understanding of reservoir performance and provide data to continually control and optimize the waterflood operation which should significantly reduce the potential for undesired water channeling.

Economic Life

Under the current primary recovery method, existing wells within the Application Area will be deemed uneconomic when the net oil price revenue stream becomes less than the producing operating costs. With positive oil production response under the proposed secondary recovery method, the economic life could be extended into the future.

Water Injection Facilities

The waterflood operation will utilize the 100/12-24-010-29W1/02 Jurassic sourced water. Injection wells will be connected to the existing high pressure water pipeline system supplying other Tundra-operated waterflood units.

A complete description of all planned system design and operational practices to prevent corrosion related failures is shown in Appendix E – “Planned Corrosion Control”. All surface facilities are built from corrosion resistant materials and wellheads will have cathodic protection when warranted to prevent corrosion. All injection flowlines will be made of fiberglass so corrosion should not be an issue. Injectors will have a packer set above the Middle Bakken formation, and the annulus between the tubing and casing will be filled with inhibited fluid.

VOLUNTARY UNITIZATION APPLICATION

As noted previously, the Application Area is not yet unitized. However, unitization will permit the implementation of Secondary Recovery within the Application Area which is forecasted to increase overall recovery of OIIP to 21.6 %. The basis for unitization is to develop the Application Area in an effective manner that will permit waterflooding. Unitization, and the implementation of an Enhanced Oil Recovery (EOR) Project, should increase the recoverable reserves via Secondary Recovery with pressure support. Additional drilling and water injection conversions to build and maintain reservoir pressure, at the discretion of the unit operator, should increase oil production and associated life of the reserves.

An approved unit is required by the Crown to permit the conversion of wells to water injection, initiate a waterflood and pursue Secondary Recovery through the execution of a formal Unit Agreement.

Proposed Unit Name:

Tundra proposes the official name of the new unit covering the Application Area to permit secondary recovery be Daly Unit No. 18.

Proposed effective date:

The proposed effective date is January 1, 2025, subject to Crown and mineral owner approvals.

Description of the unitized zone:

The unitized zone to be waterflooded shall be the Bakken / Three Forks formation.

Working interest owners & proposed operator for the unit:

Appendix A: GLJ Technical Study for Table 4 – "Tract Participants and OIIP" outlines the working interest owners for the corresponding tract within Application Area. Tundra holds a 100% working interest ownership in all the proposed tracts and will therefore hold a 100% working interest ownership in the proposed Daly Unit No. 18. The proposed unit operator will be Tundra.

Proposed tract breakdown within the Application Area:

There is proposed to be eight (8) tracts broken down as follows:

- 09-32-010-28W1
- 10-32-010-28W1
- 11-32-010-28W1
- 12-32-010-28W1
- 13-32-010-28W1
- 14-32-010-28W1
- 15-32-010-28W1
- 16-32-010-28W1

Please refer to Appendix A: GLJ Technical Study for Table 4 – "Tract Participants and OIIP"

Tract factor calculation & methodology:

Please refer to page 15 of Appendix A (GLJ Technical Study).

NOTIFICATION OF MINERAL AND SURFACE OWNERS

Tundra shall notify all surface and mineral owners of its intention to submit an application to form a new unit which will be known as Daly Unit No. 18. Copies of the Notices, and proof of service, to all surface and mineral owners will be forwarded to the Crown, when available, to complete the Daly Unit No. 18 application requirements.

Unitization and execution of the formal Daly Unit No. 18 Unit Agreement by the freehold mineral owners shall occur once the Crown has reviewed the tract factors and approved this Unit Application. The fully executed Unit Agreement will be forwarded to the Crown and complete the formation of Daly Unit No. 18.

Should the Crown have further questions or require more information, please contact:

Engineering:
Lauren Diederichs – (403) 767-1226, lauren.diederichs@tundraoilandgas.com

Geology:
Marilyn Parsons – (587) 747-5366, marilyn.parsons@tundraoilandgas.com

Land:
McKenzie Large – (403) 513-1014, mckenzie.large@tundraoilandgas.com

Yours truly,

TUNDRA OIL & GAS LIMITED

Lauren Diederichs, P.Eng., Senior Exploitation Engineer

Proposed Daly Unit No. 18

Application for Enhanced Oil Recovery Waterflood Project

List of Appendices

Appendix A	GLJ Technical Study
Appendix B	Water Injection System
Appendix C	Horizontal Injector Downhole Diagram
Appendix D	Representative Initial Pressure
Appendix E	Planned Corrosion Control

Appendix A - GLJ Technical Study

TUNDRA OIL & GAS LIMITED

DALY NO.18 WATERFLOOD STUDY

Effective August 31, 2024

Prepared by
Warren R. Bindon, M.Sc., P. Geo.
Charlene A. Maines, P. Geo.
Nicson Do, P. Eng.
Trisha S. MacDonald, P. Eng.

October 15, 2024

Project 24487

Mr. Raj Sharma
Tundra Oil & Gas Limited
1000, 715 - 5th Avenue S.W.
Calgary, Alberta T2P 2X6

Dear Mr. Sharma:

Re: Daly Field, Manitoba
N Section 32-010-28W1
Waterflood Unit Technical Study

At your request, GLJ Ltd. (GLJ) has conducted a technical review of Tundra Oil & Gas Ltd.'s (Tundra) proposed Daly 18 Unit as located in North ½ of Section 32-010-28W1 in the Daly Field, Manitoba. GLJ has conducted volumetric, fluid and production forecasts based on volumetric calculations using GLJ's geological mapping for the Lyleton "A" and Bakken zones. As part of the scope of work, GLJ has also prepared estimates of future production under primary and waterflood recovery, estimates of recovery factor and remaining recoverable volumes. This analysis incorporates well, core and log data available to June 30, 2024.

A brief discussion of the methodology estimates of petroleum initially-in-place and recoverable volumes as well as pore volume mapping, production forecasts and estimated tract factors are included in the attached report.

We trust this meets your current requirements. Should you have any questions regarding this analysis, please contact any of the undersigned.

Yours very truly,

GLJ LTD.

[redacted]

Trisha S. MacDonald, P. Eng.
Vice President Engineering

[redacted]

Mike Livingstone, P. Geo.
Vice President Geosciences

TSM/ML/ljn
Attachments

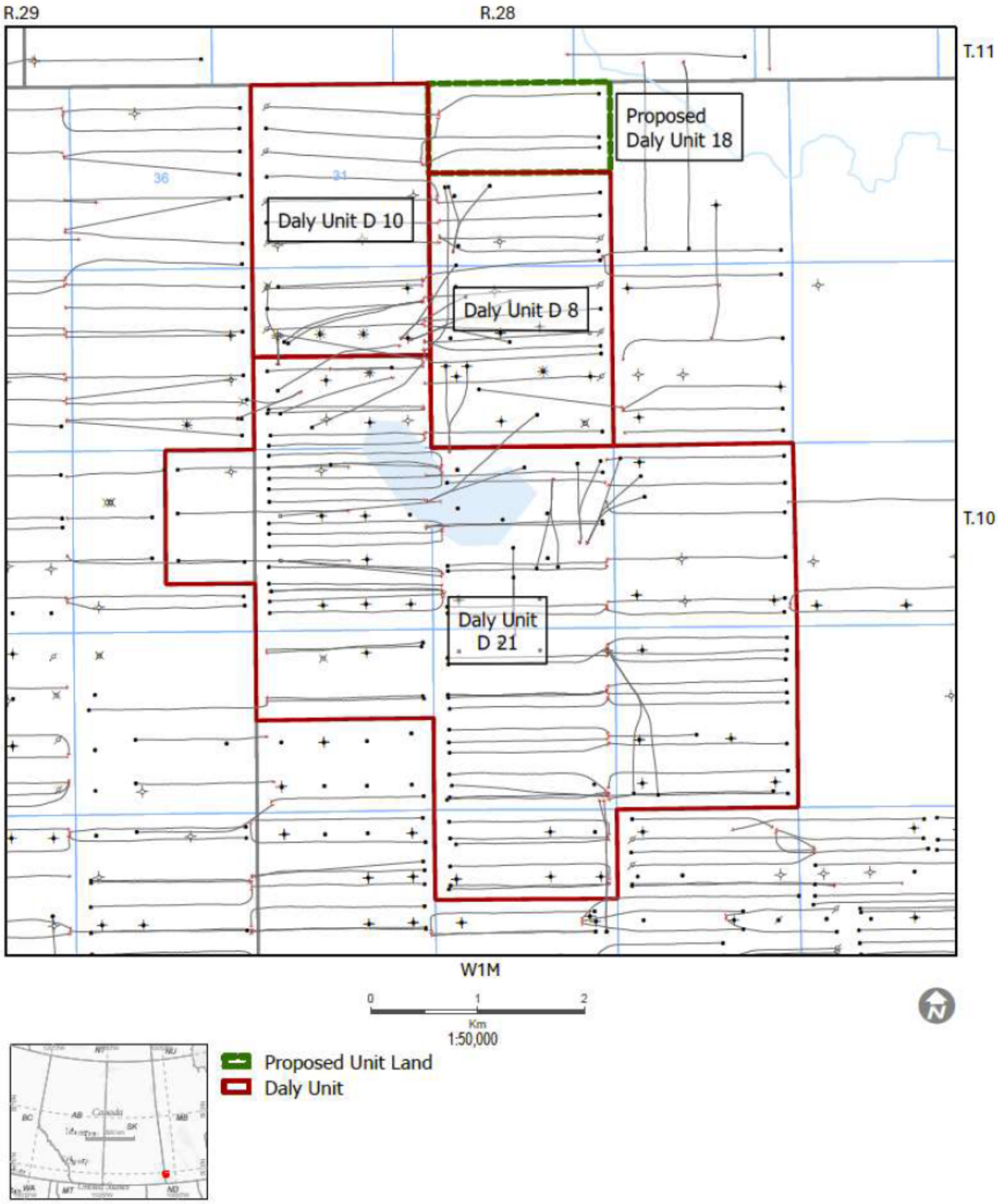
GENERAL

Tundra is proposing an additional unit in the Daly Field of Manitoba; Daly 18, N 1/2 of 32-010-28W1 (the Application Area). GLJ Ltd. (GLJ) has conducted a technical study on the Daly Field, for the purposes of estimating waterflood recovery and for use in future unitization agreements. The Daly Field was discovered in 1985 within this area Bakken-Three Forks (Torquay), pools have been developed via horizontal drilling with the addition of secondary recovery though enhanced oil recovery via waterflooding. Proposed plans are to drill additional horizontal wells with future conversion into water injection.

Several offset waterflood units exist in the Daly Field, as illustrated on Map 1. These include Daly Unit 8, Daly Unit 10 and Daly Unit 21. Active water injection is occurring in Daly Unit 8 and 10. Map 1 also illustrates the proposed Unit 18.

Based on positive waterflood response seen to date from offsetting Daly, North Ebor and Sinclair Units, Tundra is proposing further unitization in the Daly Field. At Tundra's request, GLJ has prepared estimates of Oil initially-in-place (OIIP), recoverable volumes under primary and waterflood recovery and estimates of royalty ownership for the Application Area, incorporating data available to June 30, 2024.

Please refer to Appendix I: Maps, Appendix II: Tables and Appendix III: Figures for additional Maps, Tables and Figures referenced herein.



Map 1: Daly Units

GEOLOGY

Tundra is proposing an additional unit in the Daly Field of Manitoba, proposed Daly Unit 18, located in the N 1/2 of 32-10-28W1. The Daly Field was discovered in 1985 within this area. Bakken-Three Torquay A pools have been developed via horizontal drilling with the addition of secondary recovery though enhanced oil recovery (EOR) via waterflooding. Tundra has proposed development to drill additional horizontal wells with future conversion into water injection.

The Williston Basin is an intracratonic structural and sedimentary basin that encompasses parts of Montana, North Dakota, south Dakota and Southern Saskatchewan and part of Southern Manitoba. It is a structural basin that lies above the Trans-Hudson Orogenic Belt, a Precambrian basement feature which created a weakened zone leading to sagging and resulted in the development of the basin.

Stratigraphy

The Middle Bakken within the application area is illustrated in the cross section in Map 3: Daly 18 Middle-Bakken Cross Section. The Middle Bakken is conformably overlain by the upper Bakken Shale, which in turn is overlain by the basal limestone unit of the Mississippian Lodgepole Formation. The Middle Bakken unconformably overlies the Devonian Three Forks Group (Torquay Formation) and the Three Forks Group is underlain by the Devonian Birdbear Formation.

Sedimentology

Sedimentary deposition within the Williston Basin started during the Cambrian, but most of deposition occurred during the Ordovician/Silurian and Devonian with thick limestone and dolomite accumulations. The Devonian sediments display repeated transgressive-regressive cycles linked to Elk Point basin deposition and a re-orientation of the seaway to the north as a result of activity along the Transcontinental arch.[1] Also deposited during this time were sandstones, siltstones, shales and evaporites. During the Mississippian time, subsidence continued and ended during the Pennsylvanian. Towards the end of the Cretaceous time period, basement structures were reactivated during the Laramide Orogeny which resulted in anticlinal features that serve as trapping mechanisms. The Bakken Formation subcrops east of the area of interest and is unconformably overlain by the Jurassic Amaranth Formation, Red Beds.

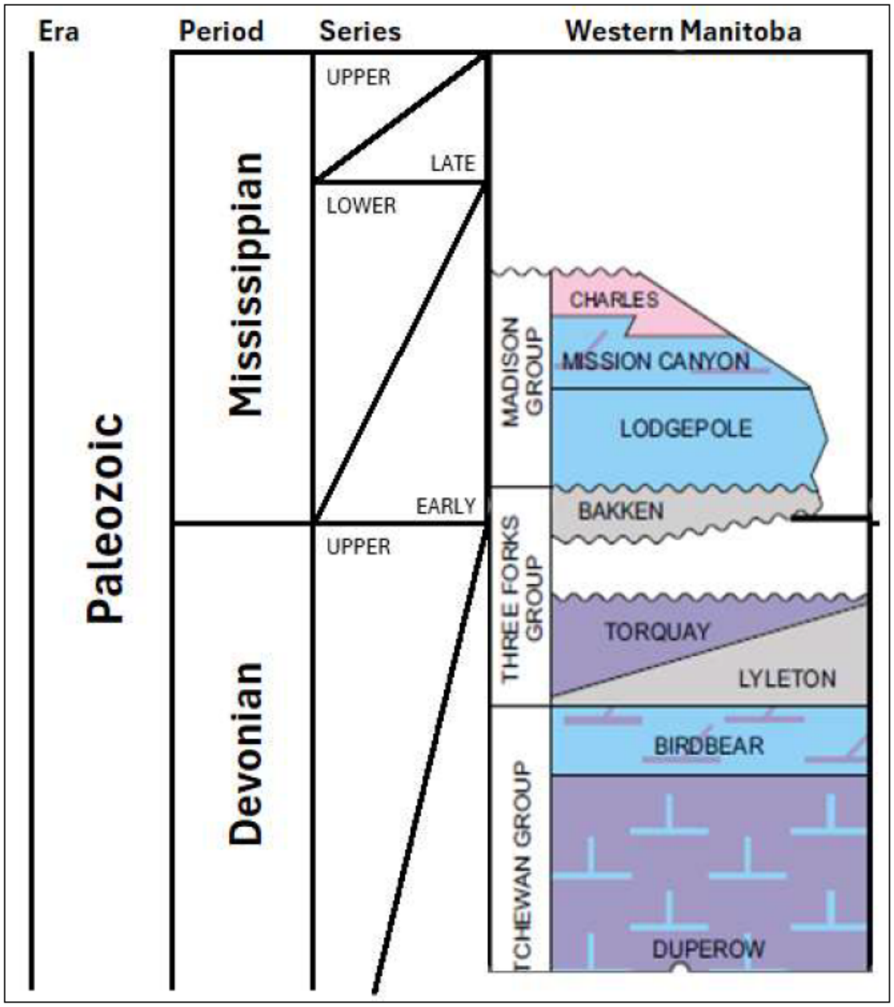


Figure 1: Stratigraphic Table of Formations – Modified after Core Laboratories, Calgary

Bakken Formation

The Bakken Formation straddles the Upper Devonian to Lower Mississippian boundary and located within the Three Forks Group and is recognized in southwestern Manitoba. The Bakken members onlap each other and thin towards the margins of the Williston Basin. In the area of proposed Daly 18 Unit, the Lower Bakken shale is not present, and the Middle Bakken siltstone/sandstone is disconformable with the red dolomitic siltstones and shales of Upper Devonian Three Forks Group (Torquay Formation). The Upper Bakken Member is conformably over lain by the cherty argillaceous limestone of the Lodgepole Formation. This contact becomes unconformable at the boundary of Manitoba and Saskatchewan where the Bakken is truncated by the Mississippian unconformity.

The Bakken is generally uniform and a thin clastic unit consisting of three members: a lower and an upper black organic rich shale, that are calcareous, fissile finely laminated and radioactive, and a middle member that is a grey quartzose sandstone/siltstone containing calcite and rare dolomite cement. Structures within the sandstone member are ripples, cross bedding, flaser bedding, interlaminations with claystone. It is a shoaling upwards succession indicative of a progression from distal to proximal shoreline, it also shows an upward increase in the sandstone to mudstone ratio.[1]

Locally, the upper and lower members of the Bakken shales show high resistivity values that are indicative of oil replacement of water within the pore space.

The Bakken is a proven low-gravity oil producing formation and is disconformable with the underlying strata which may vary depending on location. In the Daly area, the Middle Bakken sandstone is conformably to unconformably overlain by the Madison Group. The formation is continuous throughout the Williston Basin across Saskatchewan, SW Manitoba, NE Montana and SW North Dakota. The lower black shale and middle sandstone are equivalent to the Exshaw Formation in Alberta.

The Bakken in the Daly area is readily recognizable on logs; the upper shales display abnormally high gamma-ray of >200 API, and low resistivity (ohm-m) with typical blocky character.

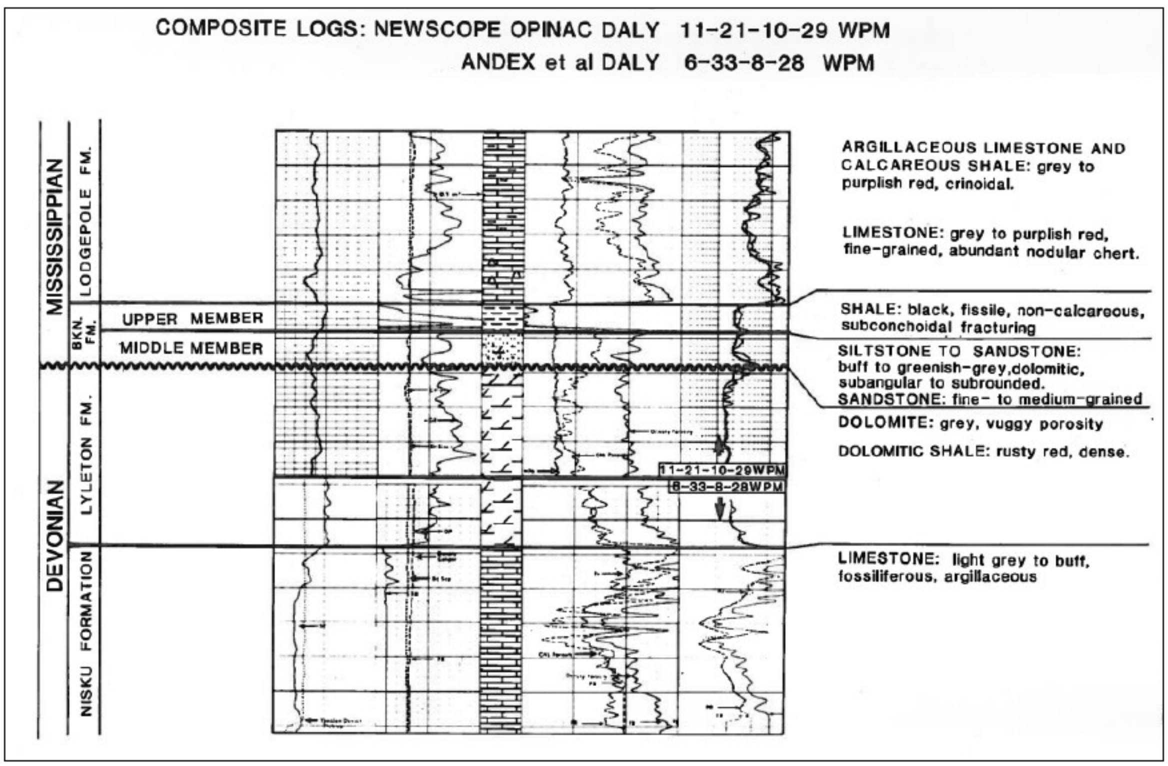


Figure 2: Composite Reference Section for Areas where the Lower Member of the Bakken is absent, Showing Generalized Stratigraphic Column[8]

Regional composite type log for the 'Daly' area 100/11-21-010-29W1/00 demonstrating the absence of the Lower Bakken shale member and the Middle Bakken resting unconformably on the Devonian Three Forks Torquay (Lyleton)[8].

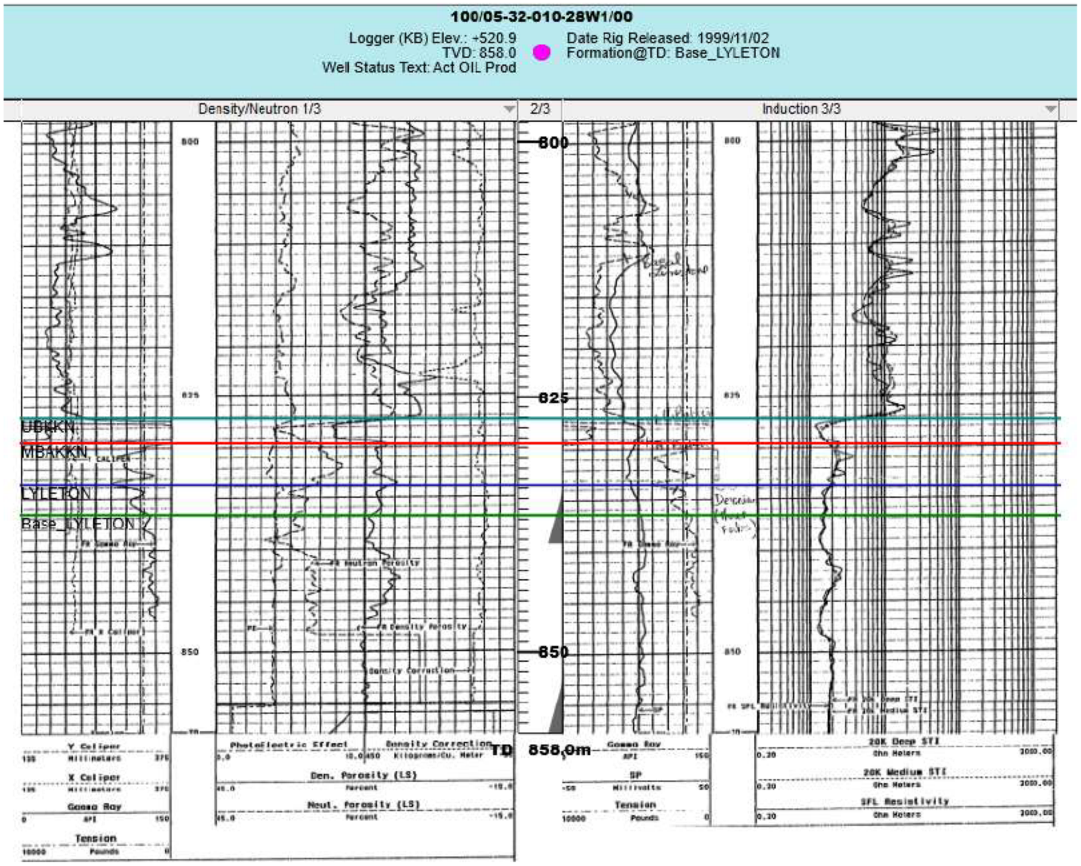


Figure 3: *Type log for the Bakken/Three Forks (Lyleton Formation) at Daly 18 Proposed Unit*

Three Forks Group (Torquay Formation)

The Three Forks (Torquay Formation) is Upper Devonian age and composed of red dolomitic shales, silty shales and argillaceous dolomite. In the Daly area, the Three Forks is unconformably overlain by the Middle Bakken, this contact is difficult to determine clearly and generally described in core samples as an abrupt change in color from the silty/argillaceous red dolomite in the Torquay to the greenish-grey argillaceous and occasionally dolomitic siltstone/sandstone of the Middle Bakken. Subtle log changes are noticed at this contact; a significant shift in the neutron porosity curve going from the Middle Bakken to the Torquay an increase in PE that coincide with a change in the gamma response and a lowered RT response in addition to subtle SP response. The Bakken-Three Forks (Torquay) pick is subject to interpretation. The Three Forks (Torquay) thins eastward and is conformable overtop the Nisku Formation and locally thickens slightly where it fills in the minor erosional lows of the Devonian, with limited extent.

Stratigraphy

The Middle Bakken Formation within the proposed Application Area can be seen on the cross section in Appendix I, Map 3. The Middle Bakken is conformably overlain by the Upper Bakken Shale, which is in turn overlain by the Basal Limestone unit of the Mississippian Lodgepole Formation. The Middle Bakken unconformably overlies the Devonian 'Torquay' or Devonian 'Three Forks Group'. The Bakken –Torquay unconformity is angular, where the top Torquay units wedge, or thin and subcrop, towards the northeast. The Torquay Formation is underlain by the Devonian Birdbear Formation.

Sedimentology

The Middle Bakken is the main reservoir section; composed of fine to very fine-grained quartz sandstone with minor amounts of dolomite, feldspar, and clays. In core samples, it often has very thin low angle to horizontal laminae, with ripples, and sometimes some small rip up clasts of the underlying Torquay at the base. The Middle Bakken is thought to have been deposited in a foreshore facies within a restricted marine seaway locally with evidence of intertidal point bar and channel thalweg depositional environments. The reservoir quality of the underlying Torquay, along with where on the foreshore the Bakken was deposited, influences the reservoir quality of the Middle Bakken greatly – resulting in a large range of reservoir quality within the area of interest.

Structure

Structure within the Application Area is generally consistent with southwest regional dip with bias towards a local low to the west. Please refer to Map 4 for Proposed Daly 18 Unit, Middle Bakken Formation – Structure (mSS) map and Map 8 for the Proposed Daly 18 Unit, Torquay Formation – Structure (mSS)

Reservoir Evaluations

The Middle Bakken reservoir within the Proposed Daly 18 Unit Application Area is continuous and of good quality. Net pay thickness of the Bakken averages around 2 metres with localized thick and then thin areas moving towards an eastward zero edge (see Map 5 Proposed Daly 18 Unit, Middle Bakken Formation – Net Pay (m)). The Torquay is generally a thinner reservoir interval with an average net pay of about 1 metre over the localized develop areas, again with a zero edge towards the eastern half of the area of interest (see Map 7 Proposed Daly 18 Unit, Torquay Formation - Net Pay (m). There are no vertical wells within the area of the proposed unit however, surrounding well control gives insight into the net pay, porosity and permeability within the proposed unit boundary.

Maps 6, 7, 10 and 11 show Phi*H (porosity*thickness) and K*H (permeability*thickness) maps for the Bakken and Torquay respectively. Phi*H is the average porosity of the reservoir multiplied by the net pay thickness in vertical wells. K*H is the summation of the permeability multiplied by the net pay thickness of the reservoir in vertical wells.

Core analysis was the preferred method of determining net pay for both the Bakken and the Torquay intervals utilizing a 0.1 mD permeability cut off. Generalized averages of permeability of the Middle Bakken are: 2.90 mD in 010-28W1, 7.39 mD in 010-29W1 and 1.36 mD in 011-28W1, after the removal of anomalous data representative of fracture samples. Average porosity over the evaluated areas, for the Middle Bakken ranges between 15.5 to 16 percent and 17.2 to 18.8 percent in the Lyleton (Three Forks).

Net oil pay was defined by logs with a limestone density porosity greater than 12 percent where no core control was available. Adjustments were made for the thin beds predominating in the areas of interest and presence of dolomite. Water saturation was calculated using Archie's equation.

The following parameters used in calculation of water saturation:

- Tortuosity constant, a = 1
- Cementation exponent, c = 1.9
- Saturation exponent, n = 2.0

Where available, core analysis porosity values were used in conjunction with Archie's equation, otherwise logs were used. A R_{XO} equivalent R_T using 1.77 multiplication factor determined from previous historical analysis in the area was implemented. Average water saturation (S_w) for the Bakken were calculated to be approximately 43 percent and the Three Forks (Torquay) was calculated to be slightly higher at approximately 52.8 percent.

Oil Initially-in-Place (OIIP)

Well tops were selected in all vertical wells throughout the study area to generate structure and thickness grids for the Middle Bakken and Torquay target zones. As some regions within the study area have limited vertical well control, target zone formation tops were selected along horizontal wellbores to add additional control for the structural mapping. In total, approximately 550 wells with picked tops were used to generate structural surfaces for the top of the Middle Bakken, top of the Lyleton and Lyleton base of reservoir.

Gross thickness grids were generated for both the Middle Bakken and Torquay zones using subtraction of these structural surfaces. A subset of wells with core data or modern wireline logging suites were evaluated to determine reservoir petrophysical properties. In total, approximately 56 wells were evaluated to generate mapping of petrophysical properties across the study area. At each petrophysically evaluated well, net-to-gross ratio, average porosity and average water saturation was determined. Trend mapping was then generated to populate areas in the study area without good petrophysical control. Net pay mapping was generated combining the gross thickness mapping with the net-to-gross mapping, while porosity and water saturation gridding was used to generate porosity-thickness (Phi*H), and hydrocarbon pore volume (HCPV) grids. OIIP estimates for the proposed unit was generated by summation of the generated OIIP mapping over relevant interest lands.

$$OIIP = \frac{Area * Net\ Pay * Porosity * (1 - Water\ Saturation)}{Initial\ Formation\ Volume\ Factor\ of\ Oil}$$

Where,

OIIP = Oil Initially-in-Place (Mbbl, or m^3)

A = Area (acres)

h= Net Pay (ft, or m)

$\emptyset$ = Porosity (fraction)

B_o = Formation Volume Factor of Oil (stb/rbbl, or sm^3/rm^3)

S_w = Water Saturation (decimal)

OIIP for the proposed unit area was estimated using geological mapping as prepared by GLJ. OIIP was calculated by legal sub-division, on a 40 acre basis. Using the results of GLJ's geological mapping, petrophysical analysis and initial properties the OIIP for the proposed Daly 18 Unit for the Bakken-Lyleton combined, is 173.8 E^3m^3 (approximately 1.1 MMbbl) oil as shown in Table 2 Daly Unit 18-OIIP Summary.

Please refer to Appendix I and II for Maps 3 through 11 and Tables 1 through 5 as referenced herein.

HISTORICAL FORECAST PRODUCTION

Oil produced from the Bakken reservoir is approximately 41.6 API, with initial solution gas – oil ratio 4.5 m^3/m^3. The Bakken reservoir in this area is water-wet, with an initial reservoir pressure (P_i) of 8,200 kPa and saturation pressure (P_{Bo}) of 1,776 Kpa. Please refer to Table 3, Bakken Formation Rock and Fluid Parameters for additional details.

Oil production within the proposed Daly 18 Unit area began in April 2014. Primary production is from two horizontal wells which achieved a combined peak oil rate of 31.55 31.55 m^3/d in November 2014. As of June 30, 2024, the wells are producing at a combined rate of 1.32 m^3/d at a 72.52 percent water cut. The wells are currently declining at a combined rate of approximately 29 percent per annum.

Current production, associated pressure depletion and production decline of the wells in the proposed Daly 18 Unit suggest that pressure restoration and management are necessary to augment oil rate decline and improve recovery of oil from the reservoir. Based on analog performance, implementing water flooding is projected to be the most effective technique to enhance reservoir performance, providing incremental oil recovery via enhanced sweep efficiency between wells and pressure maintenance.

Please refer to Appendix II for Tables 1 through 5, and Appendix III for Figures 4 through 8 for tables and figures referenced throughout this section.

Historical Bakken production is presented in Figure 4: Proposed Daly Unit No. 18 for the existing wells.

Estimated Recoverable Volumes

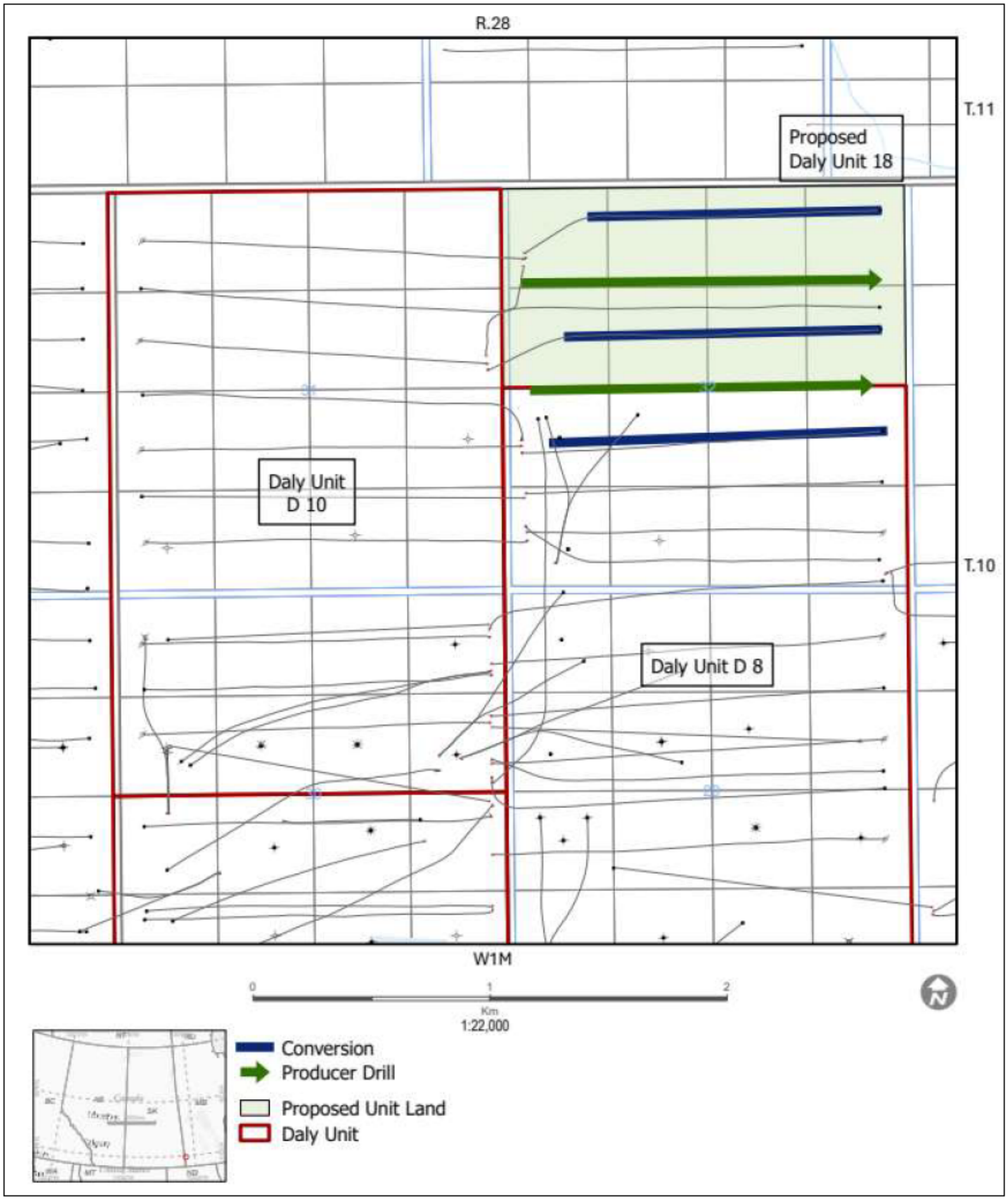
Expected recoverable volumes for the proposed Daly Unit No. 18 are derived from geological and engineering analysis that incorporates several data sources, including as open-hole log analysis, core samples, petrophysical data, seismic surveys, drilling reports, and production/fluid data. This data has been obtained from the public production database and supplemented with special tests and analysis as provided by Tundra. For producing wells, primary recoverable volumes are primarily estimated using decline curve analysis, forecast from expected initial rates as at July 1, 2024 extrapolated to final economic rates.

As of June 30, 2024, cumulative production from two producing wells within Daly Unit No. 18 totaled 17.6 E^3m^3 of oil, and 30.1 E^3m^3 of water, reflecting a 10.1 percent recovery factor (RF) of the calculated OIIP.

Expected ultimate recoverable oil volumes under primary recovery operations within the proposed Daly Unit 18 is estimated to be 19.4 E^3m^3. This represents the current development in the proposed unit area and represents 11.2 percent recovery factor of OIIP. As of July 1, 2024, the remaining recoverable volumes are estimated to be 1.8 E^3m^3. Forecasts of future daily oil rate with time and future daily oil rate versus cumulative oil produced under primary recovery mechanisms are illustrated in Figures 5 and 6.

Waterflood Forecast – EOR Secondary Volumes

The proposed Daly Unit No. 18 will be developed using 200 m well spacing, alternating water injector and oil producer trending in an East to West configuration, as illustrated on the Map 2. The development plan, well orientation and schedule is as provided by Tundra. Existing wells 00/09-32 and 00/16-32-010-28W1/00 will be converted to water injection wells and two additional horizontal oil producers will be drilled approximately 200 metres away from existing wells. The future development plan as provided by Tundra is consistent with the offsetting Bakken unit waterfloods (Daly Unit 8, Daly Unit 10, amongst others) as developed by Tundra within the Daly Field.



Map 2: Proposed Daly Unit 18 Development Plan

The oil production profile for the Daly Unit No. 18 under secondary recovery has been estimated using projections derived from standard industry best practices including decline curve analysis, volumetric analysis, analogous pool study including recovery factor expectations, as performed by GLJ. Enhanced oil recovery via waterflooding is projected to increase recoverable volumes with increased pressure maintenance and enhanced sweep efficiency. Similar projects within the Daly Field indicate that secondary recovery by waterflood can result in additional oil being extracted from the Bakken-Three Forks Formation.

The expected ultimate oil recoverable volume under waterflood operations is estimated to be 37.7 E^3m^3, with a remaining recoverable oil volume of 20.1 E^3m^3, as at July 1, 2024. Ultimate recoverable volumes represent an approximate 21.6 percent recovery factor of OIIP. An incremental 18.3 E^3m^3 of oil is projected to be recovered through secondary recovery, equivalent to 10.3 percent incremental recovery factor due to waterflooding operations.

Plots illustrating forecast daily oil production with time and daily oil production rates versus cumulative oil under waterflood operations, are illustrated in Figures 7 and 8, respectively.

Royalty and Working Interest Ownership

Tundra currently holds 100 percent working interest ownership across all the designated tracts and will maintain this ownership under unitization agreements; Tundra is the operator of existing wells producing from within the proposed Daly 18 Unit boundaries and will be the operator of the proposed Unit. Existing royalty ownership for each tract is illustrated in Table 4: Daly Unit 18 Tract Participation Summary.

Daly Unit No. 18 is proposed to consist of eight tracts based existing ownership. There is proposed to be eight tracts broken down as follows, based on legal sub-division (LSD):

- 09-32-010-28W1
- 10-32-010-28W1
- 11-32-010-28W1
- 12-32-010-28W1
- 13-32-010-28W1
- 14-32-010-28W1
- 15-32-010-28W1
- 16-32-010-28W1

Royalty ownership for the Unit has been calculated using remaining OIIP as estimated by GLJ, with the production from the horizontal wells being divided equally between the LSDs that they occupy. This calculation methodology is consistent with primary production royalty ownership estimates.

The Tract Factor contribution for each of the tracts within Daly Unit No. 18 was calculated using the OIIP by LSD, minus cumulative production to June 30, 2024, in the applicable producing horizontal or vertical well (to yield remaining oil volumes in-place).

Tract Factor formula and calculations for all individual LSD's based on the above methodology are outlined in Tract factors by participant are detailed in Table 5: Daly Unit 18 - Proposed Tract Factor Participation.

Please refer to Appendix II: Tables for Tables 1 through 5 as referenced.

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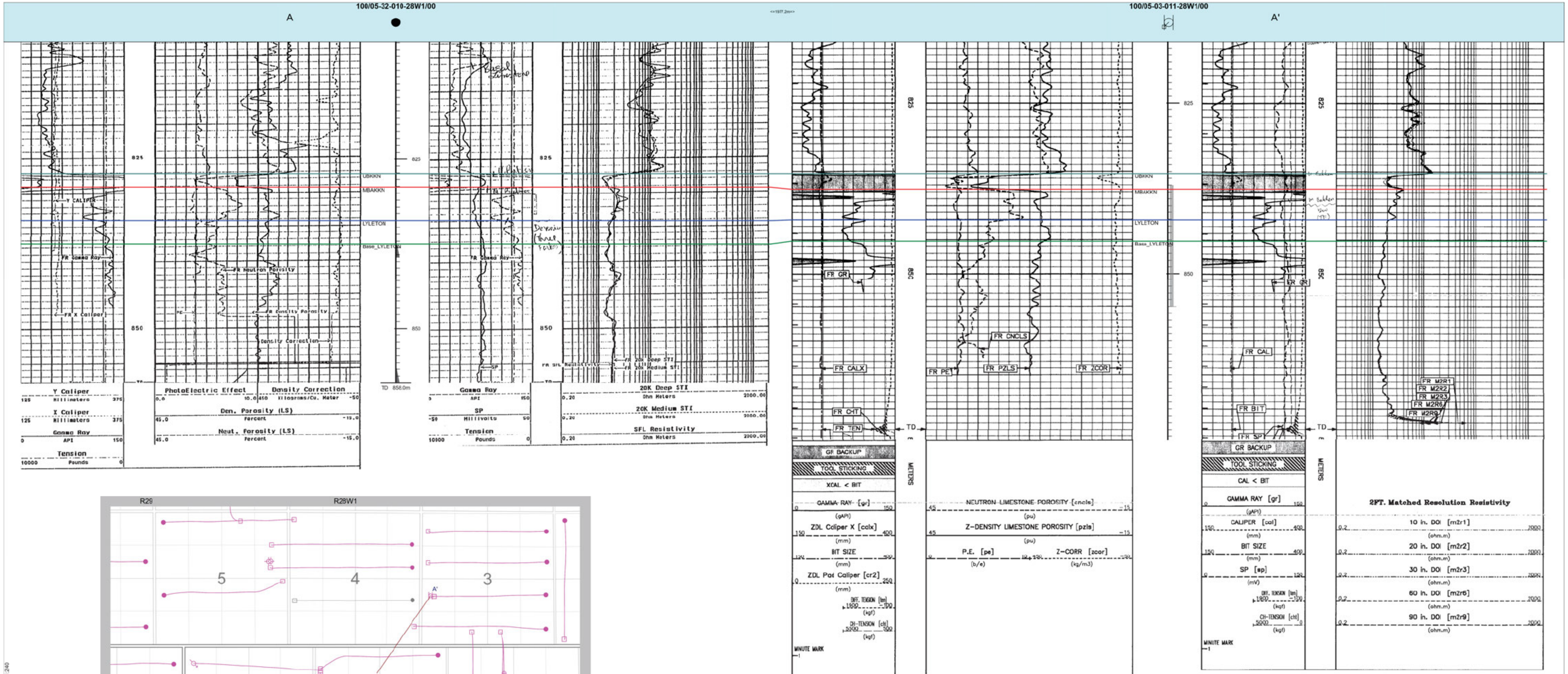
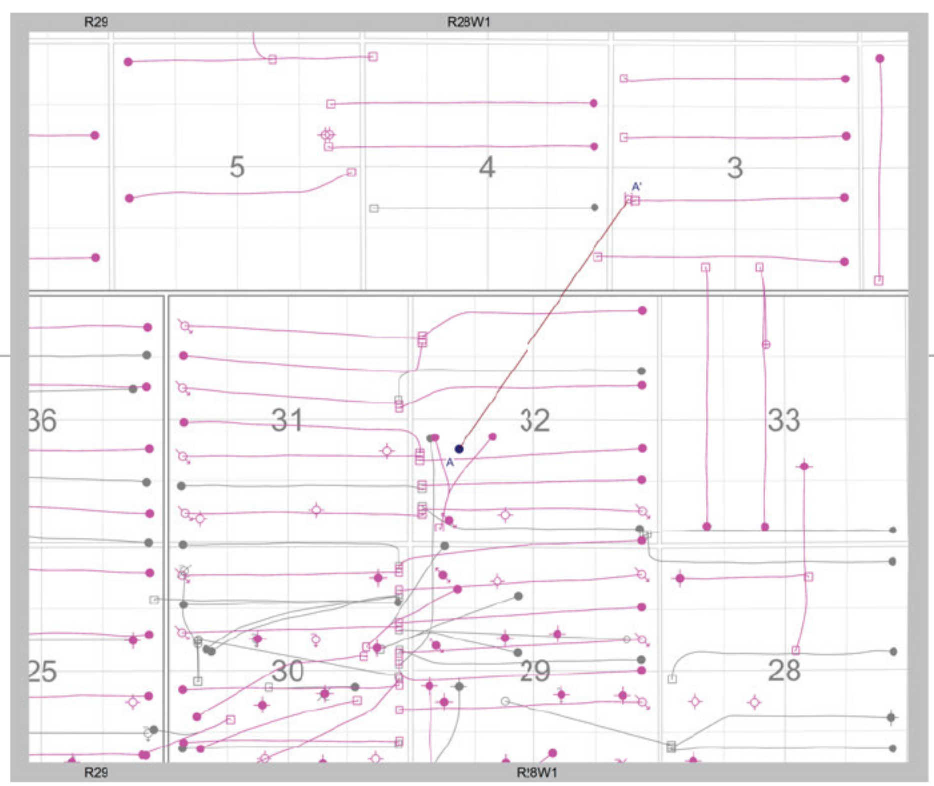
APPENDIX I: MAPS





GLJ Petroleum Consultants Ltd

Cross Section A - A'

D-18 UNIT

CROSS SECTION THROUGH UNIT

geoSCOUT	Date : 2024/08/14		By :
	Datum : UBKKN	Ref :	Scale = 1:240
	Interval : Screen Display		

Map 4

Proposed Daly Unit No.18
Middle Bakken Formation - Structure (mSS)

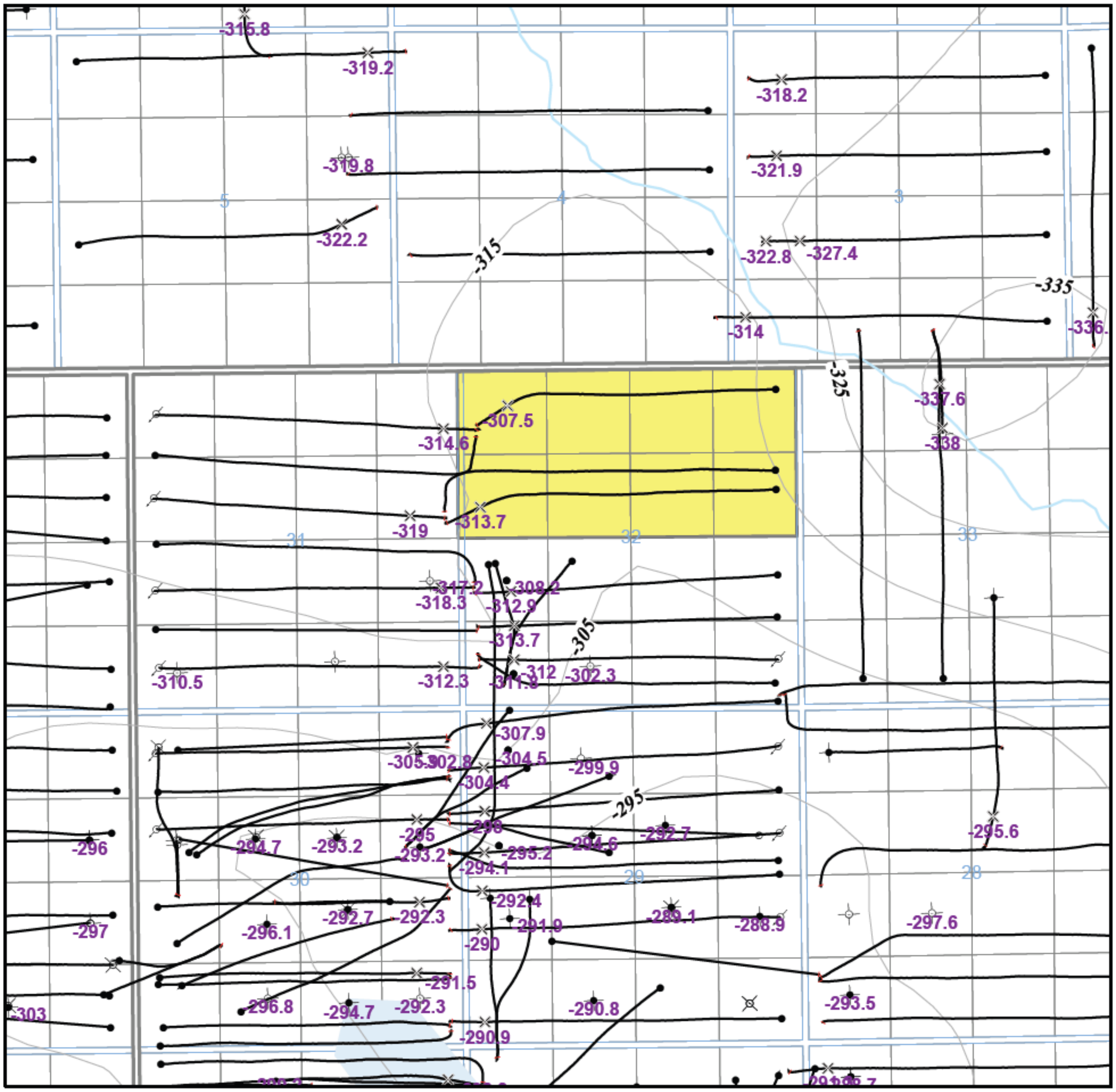
Company: Tundra Oil & Gas Limited

Property: Daly 18

Effective Date: July 1, 2024

Project: s24487/d18_appendix2

R.28



T.11

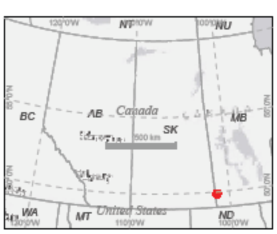
T.10

W1M

0 0.5 1

Km

1:31,250



-308.2 *Structure (mSS)*

Contour Interval = 10 metres

NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo

P:\s24487\GIS\Daly 18\Daly 18.aprx | Created by: rsamonte | Created on: October 24, 2024

World Light Gray Reference: Esri, HERE
World Light Gray Canvas Base: Esri, HERE, Garmin, USGS, EPA, NRCan

Map 5

Proposed Daly Unit No.18

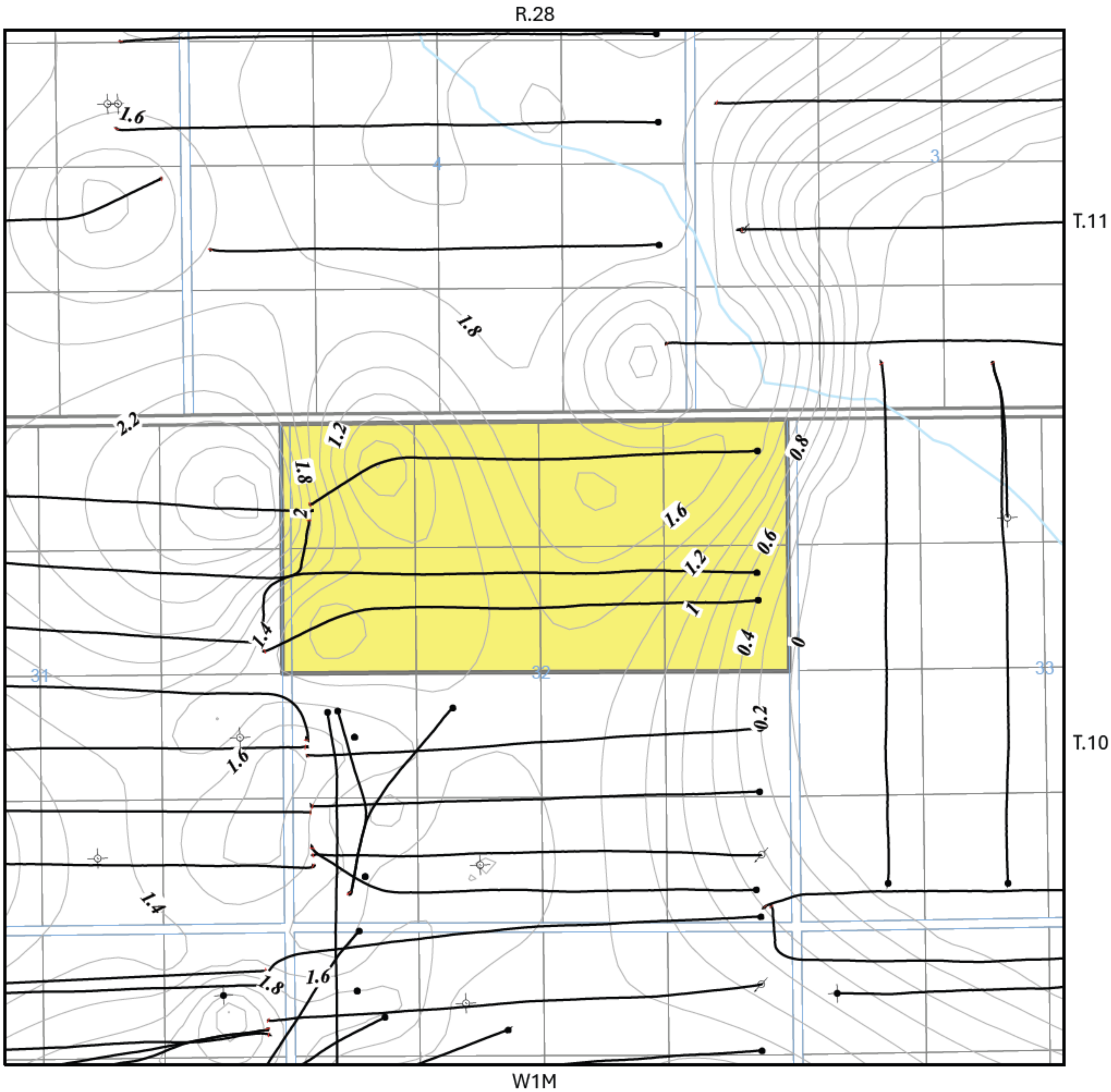
Middle Bakken Formation - Net Pay (m)

Company: Tundra Oil & Gas Limited

Property: Daly 18

Effective Date: July 1, 2024

Project: s24487/d18_appendix3



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Km
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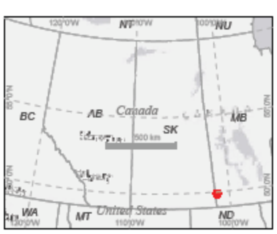

Contour Interval = 0.2 metres

NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo

P:\s24487\GIS\Daly 18\Daly 18.aprx | Created by: rsamonte | Created on: October 24, 2024

GLJ

Map 6

Proposed Daly Unit No.18
Middle Bakken Formation - Phi*H (m)

Company: Tundra Oil & Gas Limited
Property: Daly 18

Effective Date: July 1, 2024
Project: s24487/d18_appendix4

R.28

T.11

T.10

W1M

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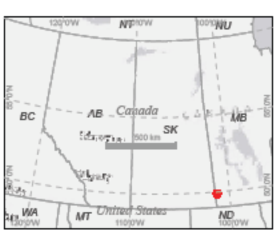
Km
1:20,000



Contour Interval = 0.05 metres

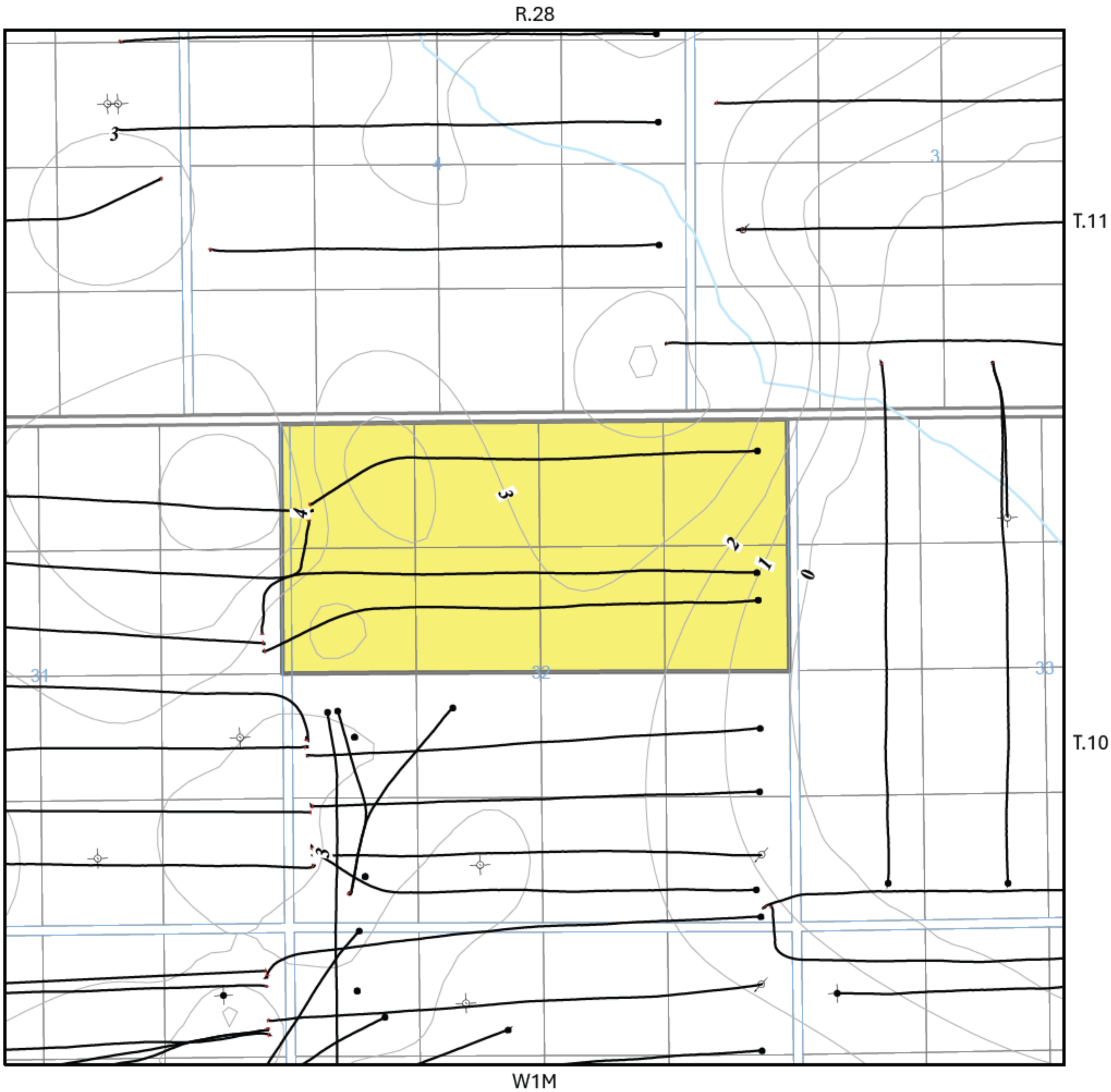
NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo
P:\s24487\GIS\Daly 18\Daly 18.aprx | Created by: rsamonte | Created on: October 24, 2024

Map 7

Proposed Daly Unit No.18
Middle Bakken Formation - k*H (mD*m)

Company: Tundra Oil & Gas Limited
Property: Daly 18

Effective Date: July 1, 2024
Project: s24487/d18_appendix5



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Km
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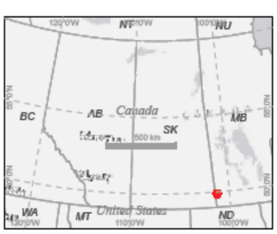


Contour Interval = 1 metres

NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo
P:\s24487\GIS\Daly 18\Daly 18.aprx | Created by: rsamonte | Created on: October 24, 2024

Map 8

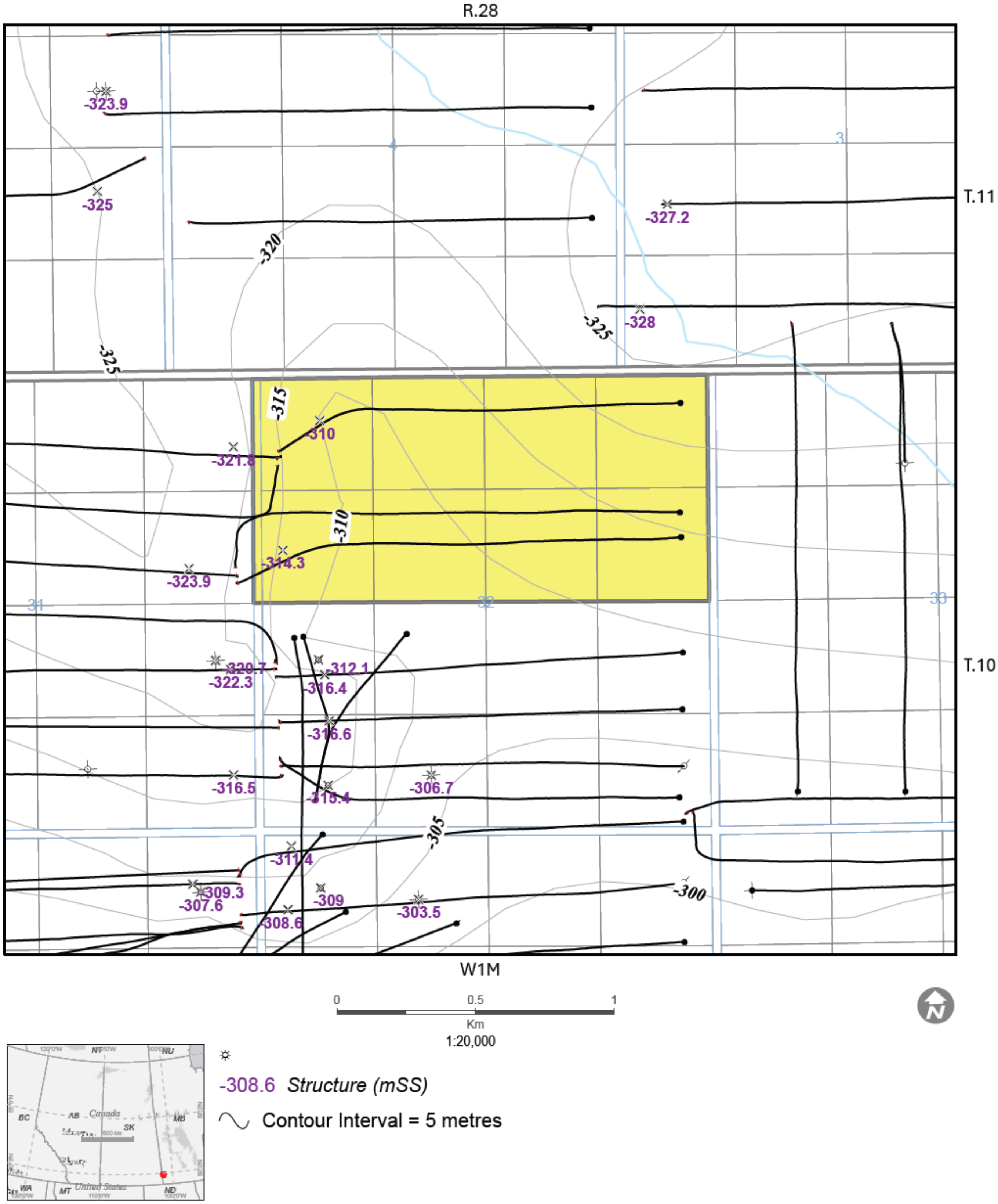
Proposed Daly Unit No.18 Torquay A Formation - Structure (mSS)

Company: Tundra Oil & Gas Limited

Property: Daly 18

Effective Date: July 1, 2024

Project: s24487/d18_appendix6



NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo

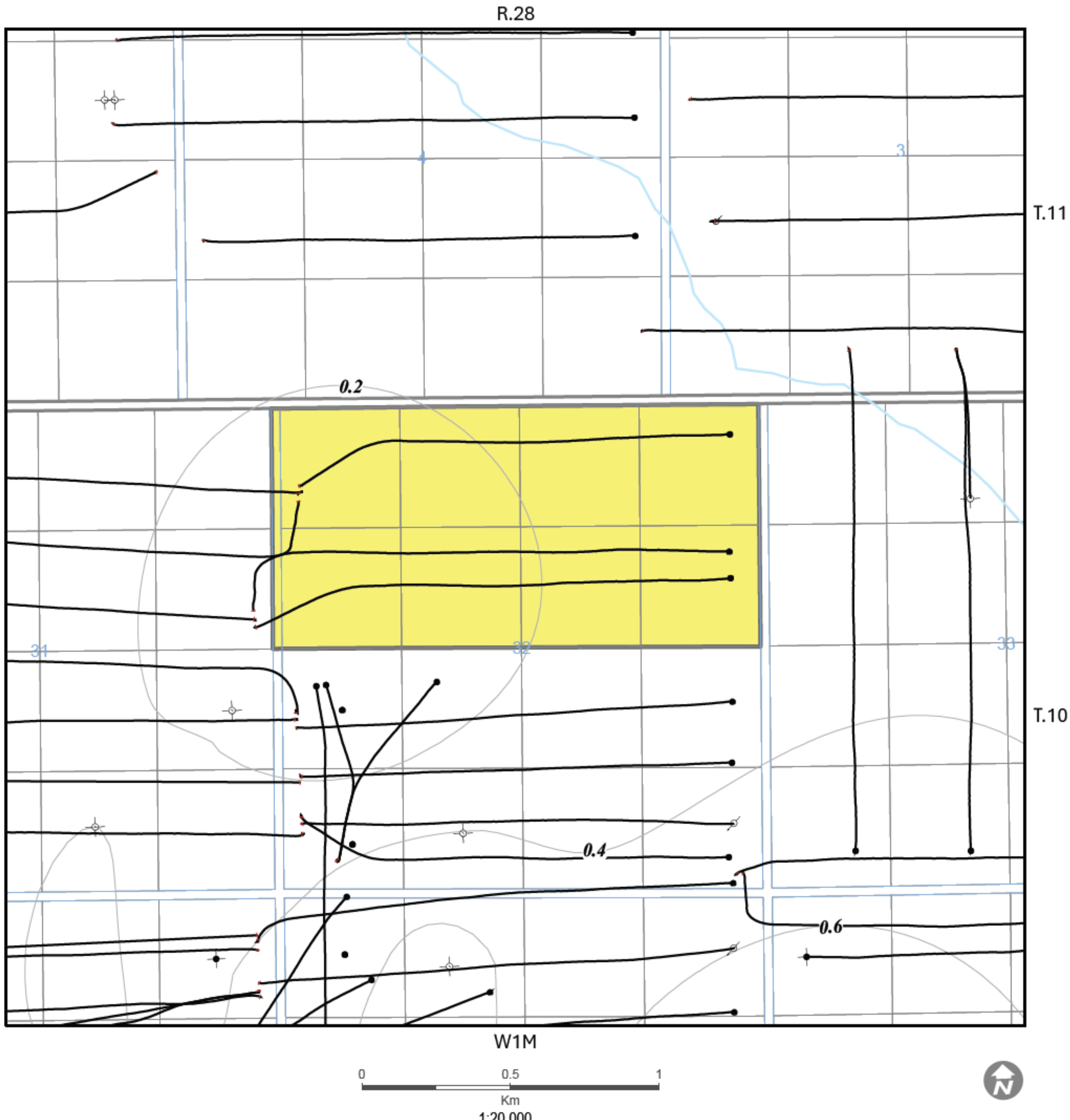
P:\s24487\GIS\Daly 18\Daly 18.aprx | Created by: rsamonte | Created on: October 24, 2024

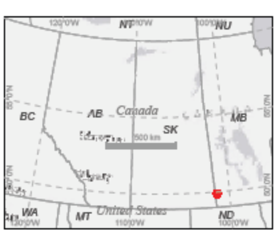
Map 9

Proposed Daly Unit No.18
Torquay A Formation - Net Pay (m)

Company: Tundra Oil & Gas Limited
Property: Daly 18

Effective Date: July 1, 2024
Project: s24487/d18_appendix7





Contour Interval = 0.2 metres

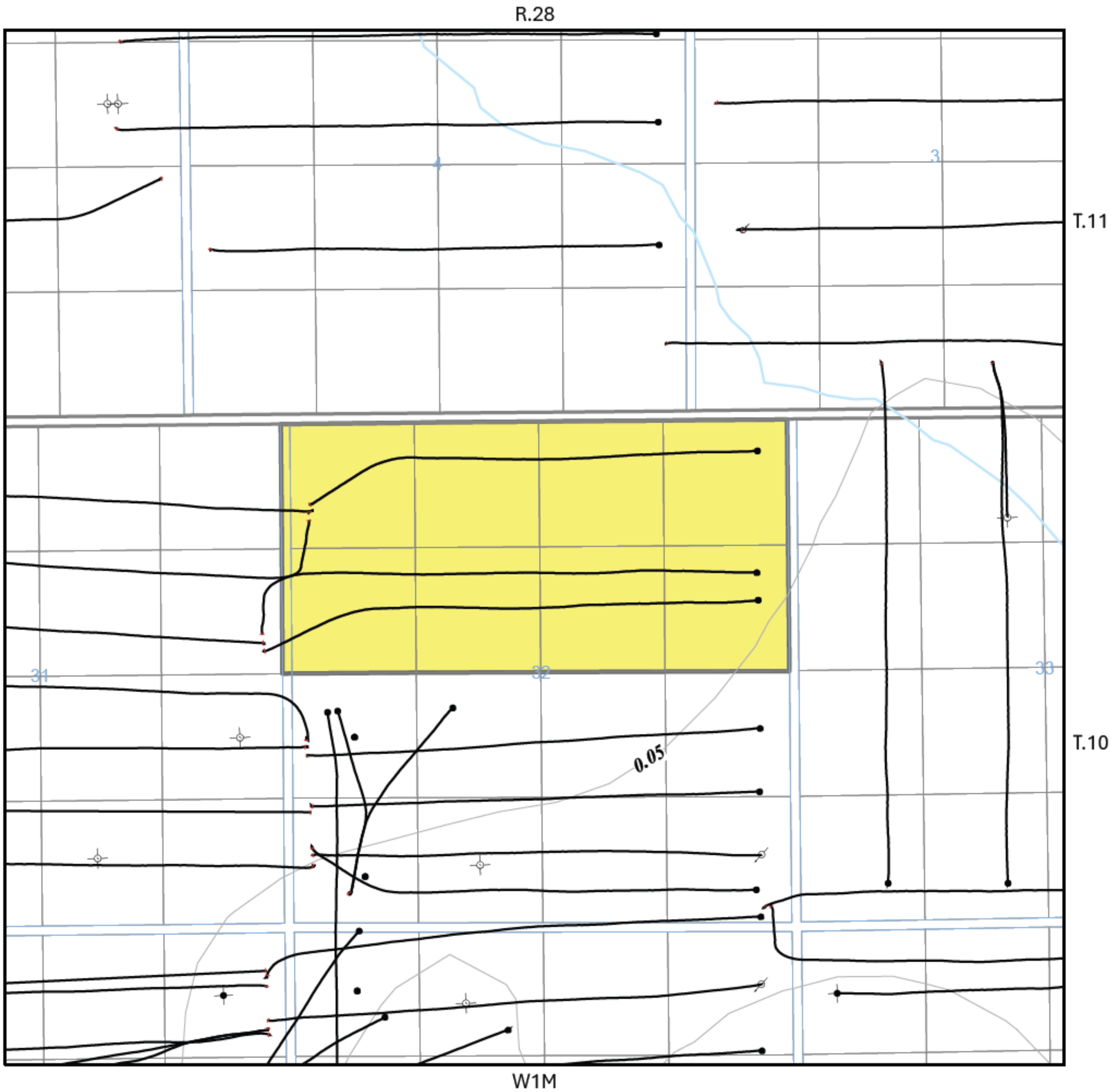
NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo
P:\s24487\GIS\Daly 18\Daly 18.aprx | Created by: rsamonte | Created on: October 24, 2024

Map 10

Proposed Daly Unit No.18
Torquay A Formation - Phi*H (m)

Company: Tundra Oil & Gas Limited
Property: Daly 18

Effective Date: July 1, 2024
Project: s24487/d18_appendix8



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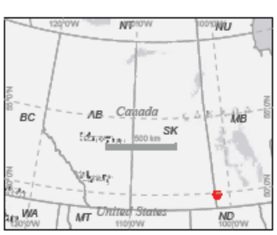


Contour Interval = 0.05 metres

NAD 1927 UTM Zone 14N	Well Source: October, 2024	Geologist: wbindon	Engineer: ndo
P:\s24487\GIS\Daly 18\Daly 18.aprx		Created by: rsamonte	Created on: October 24, 2024

World Light Gray Reference: Esri, HERE
World Light Gray Canvas Base: Esri, HERE, Garmin, USGS, EPA, NRCan

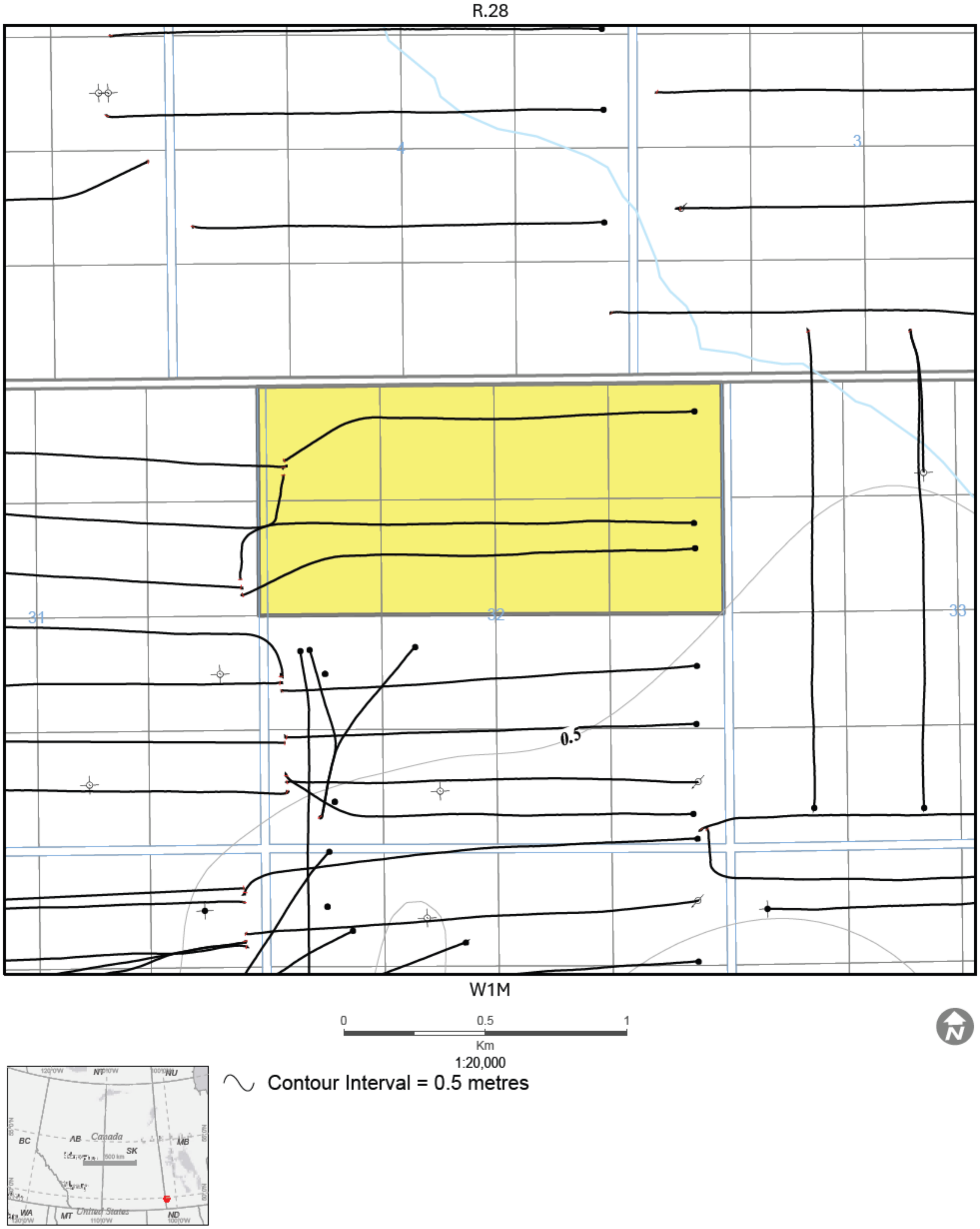
Map 11
Proposed Daly Unit No.18
Torquay A Formation - k*H (mD*m)

Company: Tundra Oil & Gas Limited

Property: Daly 18

Effective Date: July 1, 2024

Project: s24487/d18_appendix9



NAD 1927 UTM Zone 14N | Well Source: October, 2024 | Geologist: wbindon | Engineer: ndo

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APPENDIX II: TABLES

TABLE 1: PROPOSED DALY UNIT NO. 18 WELL LIST AND STATUS

UWI	License Number	Type	Pool Name	Producing Zone	Mode
100/09-32-010-28W1/00	009851	Horizontal	BAKKEN-THREE FORKS A	BAKKENU	Pumping
100/16-32-010-28W1/00	009850	Horizontal	BAKKEN-THREE FORKS A	BAKKENM	Pumping

UWI	On Production Date	Last Production Date	Gross Cal Dly Oil (m3/d)	Gross Monthly Oil (m3)	Gross Cum Prd Oil (m3)	Gross Cal Dly Water (m3/d)	Gross Monthly Water (m3)	Gross Cum Prod Water (m3)	WCT (%)
100/09-32-010-28W1/00	2014-04-02	2024-06-30	0.68	20.30	10005.20	0.64	19.10	17203.50	48.48
100/16-32-010-28W1/00	2014-09-18	2024-06-30	0.64	19.10	7556.30	2.83	84.90	12874.70	81.63

TABLE 2: PROPOSED DALY UNIT NO. 18 VOLUMETRIC SUMMARY AND OIIP

Bakken						
LSD	Net Pay (m)	Area (m^2)	Porosity	Sw	OIIP (m^3)	OIIP (bbls)
09-32-010-28W1	0.7	163,971	0.162	0.41	10,521	66,176
10-32-010-28W1	1.4	163,652	0.162	0.41	20,994	132,050
11-32-010-28W1	1.2	163,336	0.163	0.41	17,969	113,022
12-32-010-28W1	1.1	175,227	0.164	0.41	18,521	116,497
13-32-010-28W1	1.3	175,191	0.165	0.41	20,907	131,502
14-32-010-28W1	1.3	163,303	0.164	0.41	20,204	127,084
15-32-010-28W1	1.7	163,622	0.163	0.41	25,840	162,533
16-32-010-28W1	1.3	163,943	0.163	0.41	20,497	128,924
				Total	155,451	977,787

Lyleton						
LSD	Net Pay (m)	Area (m^2)	Porosity	Sw	OIIP (m^3)	OIIP (bbls)
09-32-010-28W1	0.3	163,971	0.160	0.56	3,251	20,446
10-32-010-28W1	0.2	163,652	0.161	0.57	2,484	15,624
11-32-010-28W1	0.2	163,336	0.161	0.58	1,658	10,430
12-32-010-28W1	0.1	175,227	0.161	0.58	1,347	8,472
13-32-010-28W1	0.2	175,191	0.160	0.58	1,965	12,361
14-32-010-28W1	0.2	163,303	0.160	0.57	2,037	12,810
15-32-010-28W1	0.2	163,622	0.160	0.57	2,559	16,094
16-32-010-28W1	0.3	163,943	0.160	0.56	3,137	19,731
				Total	18,437	115,968

Table 3 PROPOSED DALY UNIT NO. 18 BAKKEN FORMATION ROCK AND FLUID PARAMETERS			
			Source Well
Formation Pressure (kPa)	8200	Initial Average Reservoir Pressure	100/12-31-010-28W1/00
Formation Temperature (˚C)	30		100/12-31-010-28W1/00
Saturation Pressure (kPa)	1776	Bubble Point	100/12-31-010-28W1/00
GOR (m^3/m^3)	4.5	Gas Oil Ratio	100/12-31-010-28W1/00
API Oil Gravity	41.6		100/12-31-010-28W1/00
Swi (fraction)	0.41	Initial Average Water Saturation	100/09-32-010-28W1/00
Produced Water Specific Gravity	1.11		100/11-07-007-29W1/00
Produced Water pH	7.2		100/10-29-010-28W1/00
Produced Water TDS (kg/m^3)	166.81		100/10-29-010-28W1/00
Wettability	Water-wet		100/01-04-008-29W1/00

TABLE NO. 4: PROPOSED DALY UNIT NO. 18 TRACT PARTICIPATION

Working Interest				Royalty Interest		OIIP - Cum Tract Participation
Tract No.	Land Description	Owner	Share (%)	Owner	Share (%)	
1	09-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.086328125	7.209311301
				JPL Legacy Inc.	16.086328125	
				[redacted]	16.086328125	
				Bank of Nova Scotia Trust Company	21.448437500	
				New North Resources Ltd. (Lintus Resources Limited)	16.086328125	
				Missing Royalty Owner 28	12.256250000	
				Minister of Finance - Manitoba	1.950000000	
2	10-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.406250000	13.418275244
				JPL Legacy Inc.	16.406250000	
				[redacted])	16.406250000	
				Bank of Nova Scotia Trust Company	21.875000000	
				New North Resources Ltd. (Lintus Resources Limited)	16.406250000	
				Missing Royalty Owner 28	12.500000000	
3	11-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.406250000	10.954857577
				JPL Legacy Inc.	16.406250000	
				[redacted]	16.406250000	
				Bank of Nova Scotia Trust Company	21.875000000	
				New North Resources Ltd. (Lintus Resources Limited)	16.406250000	
				Missing Royalty Owner 28	12.500000000	
4	12-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.406250000	11.109087172
				JPL Legacy Inc.	16.406250000	
				[redacted]	16.406250000	
				Bank of Nova Scotia Trust Company	21.875000000	
				New North Resources Ltd. (Lintus Resources Limited)	16.406250000	
				Missing Royalty Owner 28	12.500000000	
5	13-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.406250000	13.422317572
				JPL Legacy Inc.	16.406250000	
				[redacted]	16.406250000	
				Bank of Nova Scotia Trust Company	21.875000000	
				New North Resources Ltd. (Lintus Resources Limited)	16.406250000	
				Missing Royalty Owner 28	12.500000000	
6	14-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.406250000	13.018753107
				JPL Legacy Inc.	16.406250000	
				[redacted]	16.406250000	
				Bank of Nova Scotia Trust Company	21.875000000	
				New North Resources Ltd. (Lintus Resources Limited)	16.406250000	
				Missing Royalty Owner 28	12.500000000	
7	15-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	16.406250000	16.957741786
				JPL Legacy Inc.	16.406250000	
				[redacted]	16.406250000	
				Bank of Nova Scotia Trust Company	21.875000000	
				Lintus Resources Limited (New North Resources Ltd.)	16.406250000	
				Missing Royalty Owner 28	12.500000000	
8	16-32-010-28W1M	Tundra Oil & Gas Limited	100	[redacted]	15.495703125	13.909656241
				JPL Legacy Inc.	15.495703125	
				[redacted]	15.495703125	
				Bank of Nova Scotia Trust Company	20.660937500	
				New North Resources Ltd. (Lintus Resources Limited)	15.495703125	
				Missing Royalty Owner 28	11.806250000	
				Minister of Finance - Manitoba	5.550000000	

TABLE NO. 5: PROPOSED DALY UNIT NO. 18 TRACT FACTOR CALCULATIONS

TRACT FACTOR BASED ON OIL-IN-PLACE (OOIP) - CUMULATIVE PRODUCTION TO JUNE 30, 2024

LS-SE	Tract	OOIP (m3)	HZ Wells Alloc Prod (m^3)	Vert Wells Cum Prodn (m3)	Sum Hz +Vert Alloc Cum Prodn	OOIP - Cum Prodn (m3)	Tract Factor (%)	Tract
09-32	09-32-010-28W1	13771.36	2501.30	0	2501.30	11270.06	7.209311301	09-32-010-28W1
10-32	10-32-010-28W1	23477.62	2501.30	0	2501.30	20976.32	13.418275244	10-32-010-28W1
11-32	11-32-010-28W1	19626.64	2501.30	0	2501.30	17125.34	10.954857577	11-32-010-28W1
12-32	12-32-010-28W1	19867.74	2501.30	0	2501.30	17366.44	11.109087172	12-32-010-28W1
13-32	13-32-010-28W1	22871.71	1889.08	0	1889.08	20982.64	13.422317572	13-32-010-28W1
14-32	14-32-010-28W1	22240.83	1889.08	0	1889.08	20351.76	13.018753107	14-32-010-28W1
15-32	15-32-010-28W1	28398.52	1889.08	0	1889.08	26509.44	16.957741786	15-32-010-28W1
16-32	16-32-010-28W1	23633.55	1889.08	0	1889.08	21744.48	13.909656241	16-32-010-28W1

APPENDIX III: FIGURES

Figure 4 - Proposed Daly Unit No. 18 Historical Bakken Production

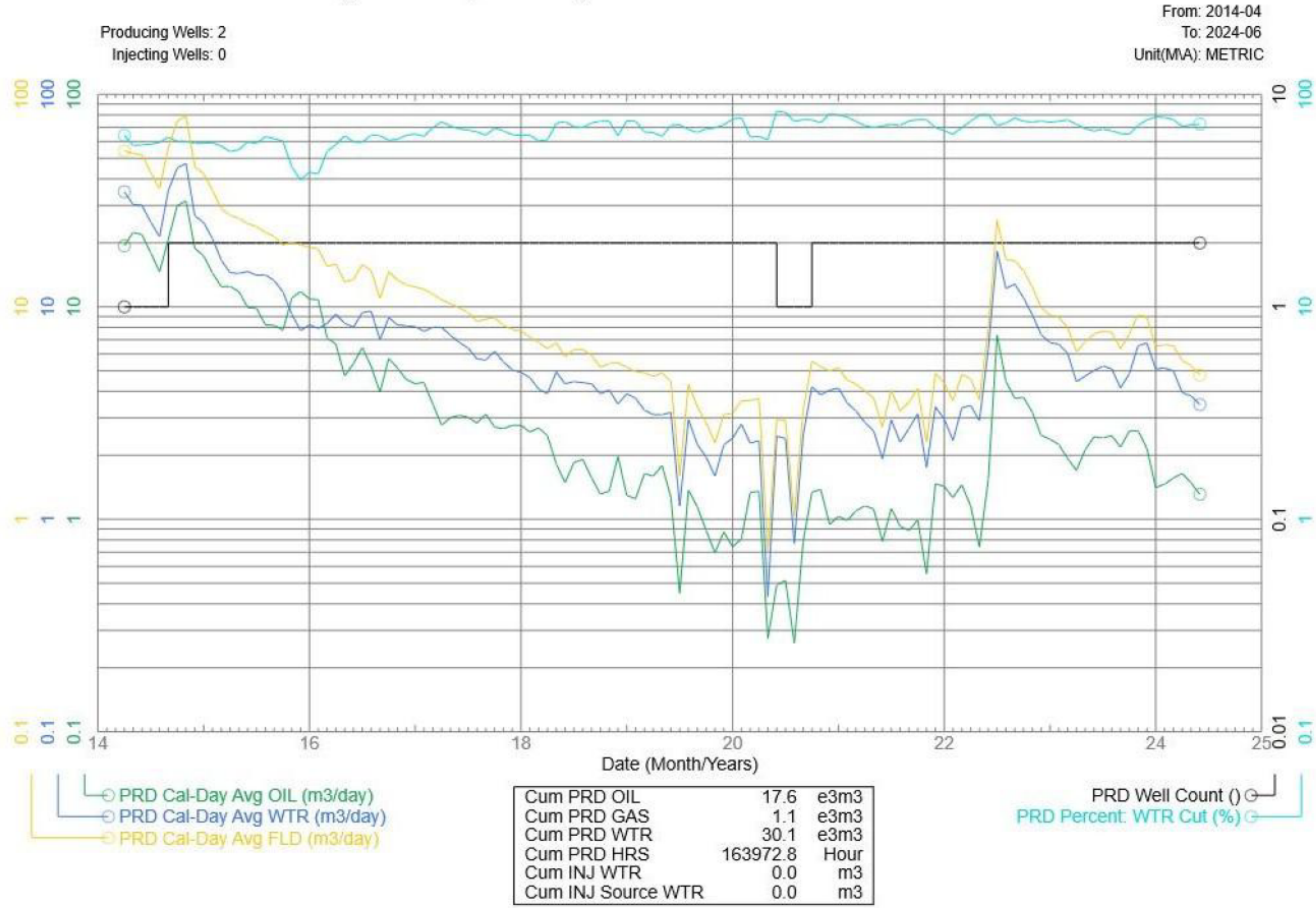
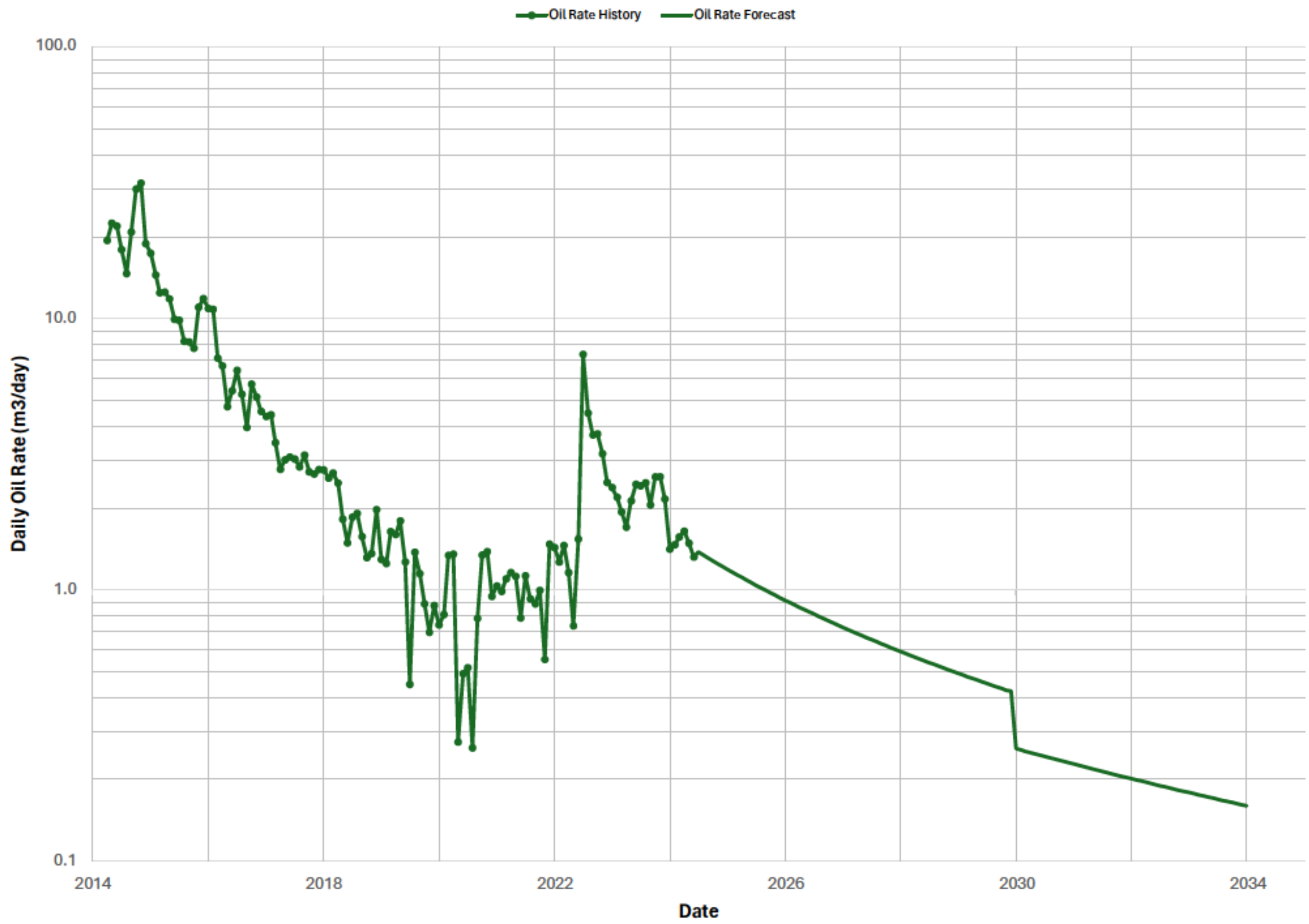
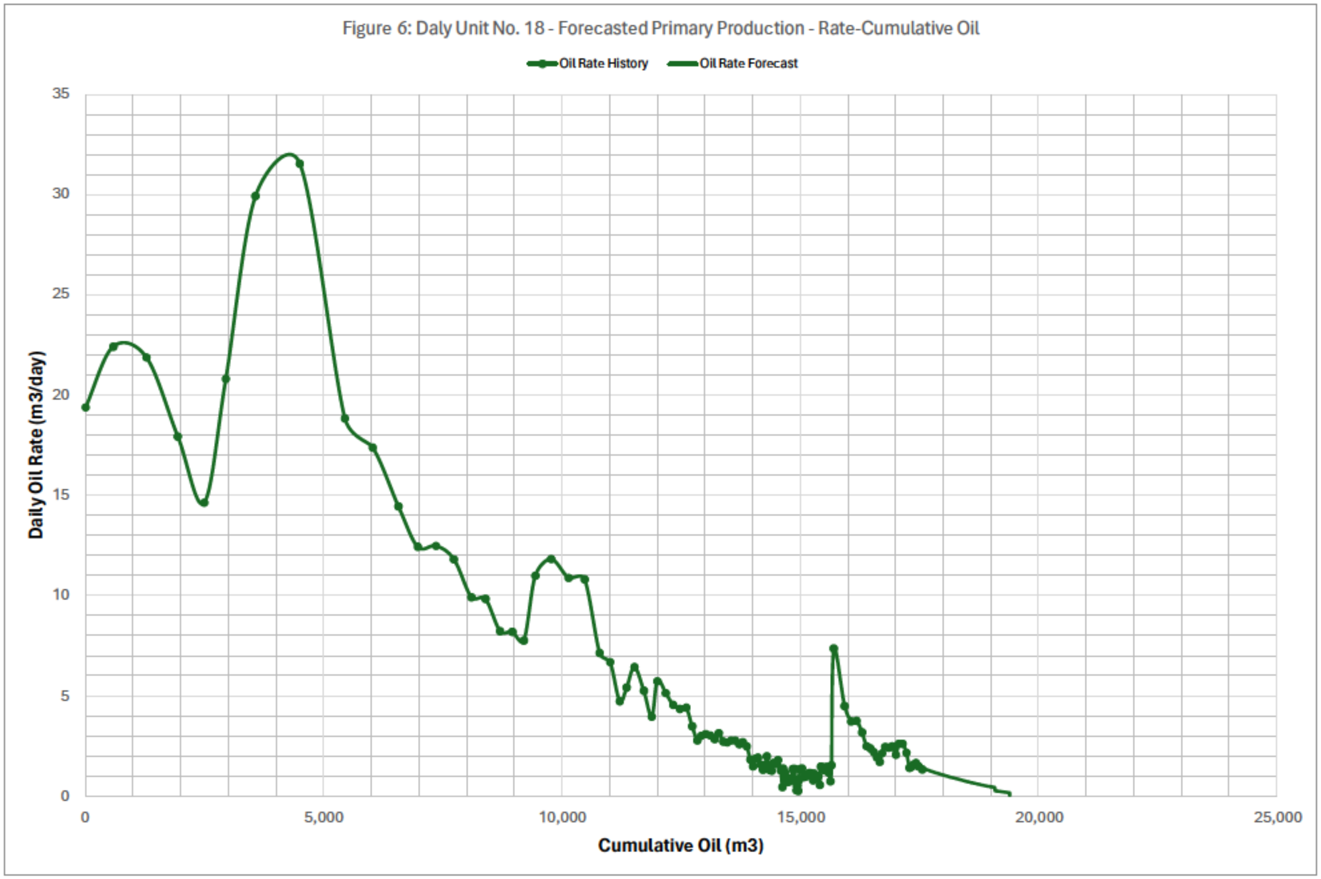


Figure 5: Daly Unit No. 18 - Forecasted Primary Production - Rate-Time



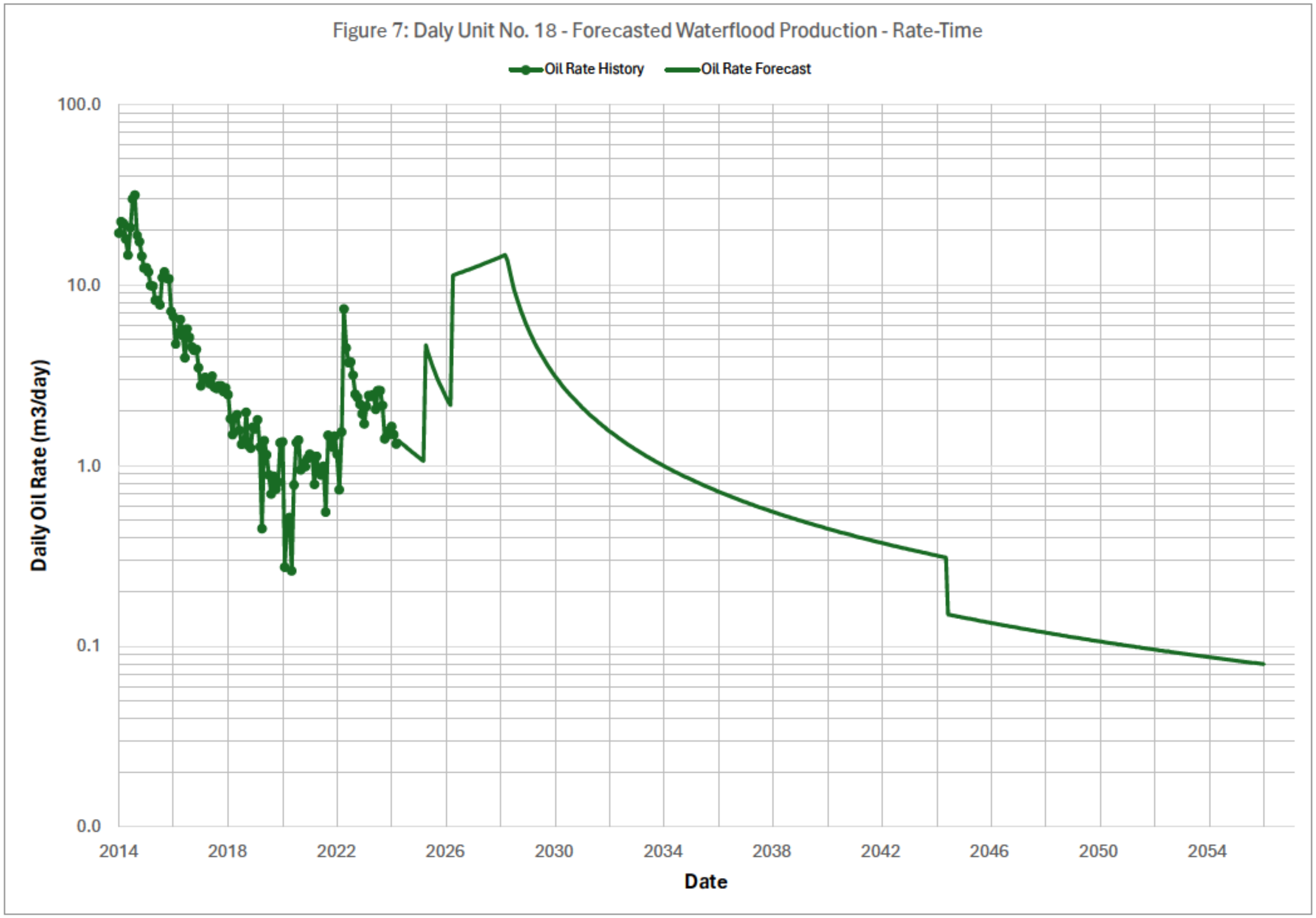
Volume Summary		
Oil	Cum (E3m3)	17.56
	Rem Rec (E3m3)	1.84
	Ult Rec (E3m3)	19.40
Gas	Cum (E3m3)	12.08
	Rem Rec (E3m3)	21.31
	Ult Rec (E3m3)	33.39
Water	Cum (E3m3)	30.08
	Rem Rec (E3m3)	-
	Ult Rec (Em3)	-
Field	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (Em3)	0
NGL	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (Em3)	0

Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2024-07-01
Forecast End	2034-02-01
Presentation	Unit Plots
Initial Rate (m3/d)	1.32
Final Rate (m3/d)	0.16
Ult Rec (m3)	19.40
Cum (m3)	17.56
Rem Rec (m3)	1.84
Res Life (yrs)	9.41
RLI Full Year (yrs)	5.36
Res Half Life (yrs)	3.19



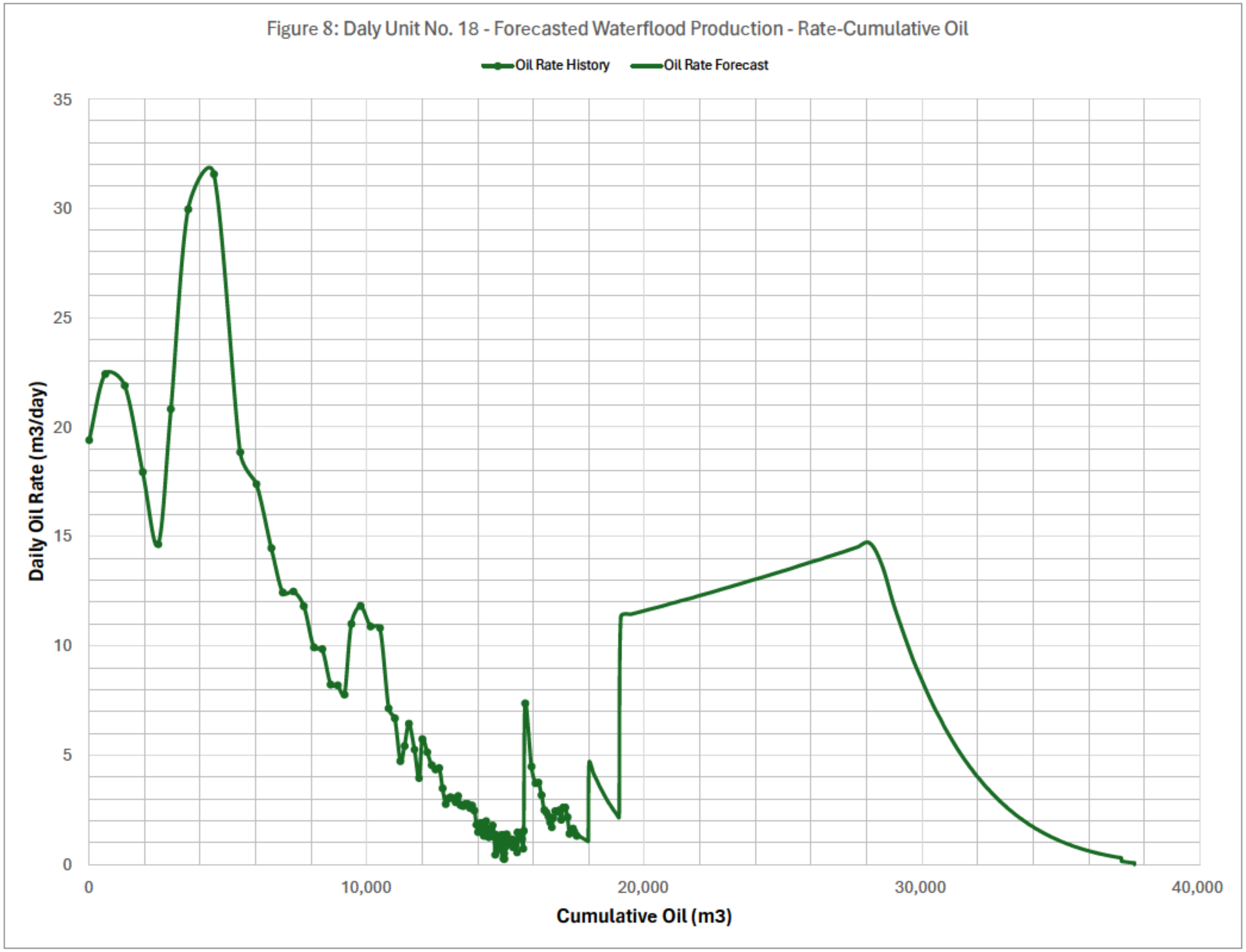
Volume Summary		
Oil	Cum (E3m3)	17.56
	Rem Rec (E3m3)	1.84
	Ult Rec (E3m3)	19.40
Gas	Cum (E3m3)	12.08
	Rem Rec (E3m3)	21.31
	Ult Rec (E3m3)	33.39
Water	Cum (E3m3)	30.08
	Rem Rec (E3m3)	-
	Ult Rec (Em3)	-
Field	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (Em3)	0
NGL	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (Em3)	0

Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2024-07-01
Forecast End	2034-02-01
Presentation	Unit Plots
Initial Rate (m3/d)	1.32
Final Rate (m3/d)	0.16
Ult Rec (m3)	19.40
Cum (m3)	17.56
Rem Rec (m3)	1.84
Res Life (yrs)	9.41
RLI Full Year (yrs)	5.36
Res Half Life (yrs)	3.19



Volume Summary		
Oil	Cum (E3m3)	17.56
	Rem Rec (E3m3)	20.09
	Ult Rec (E3m3)	37.65
Gas	Cum (E3m3)	12.08
	Rem Rec (E3m3)	201.24
	Ult Rec (E3m3)	213.32
Water	Cum (E3m3)	30.08
	Rem Rec (E3m3)	-
	Ult Rec (E3m3)	-
Field	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (E3m3)	0
NGL	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (E3m3)	0

Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2024-07-01
Forecast End	2056-05-01
Presentation	Unit Plots
Initial Rate (m3/d)	1.32
Final Rate (m3/d)	0.16
Ult Rec (m3)	37.65
Cum (m3)	17.56
Rem Rec (m3)	20.09
Res Life (yrs)	30.82
RLI Full Year (yrs)	6.89
Res Half Life (yrs)	3.47



Volume Summary		
Oil	Cum (E3m3)	17.56
	Rem Rec (E3m3)	20.09
	Ult Rec (E3m3)	37.65
Gas	Cum (E3m3)	12.08
	Rem Rec (E3m3)	201.24
	Ult Rec (E3m3)	213.32
Water	Cum (E3m3)	30.08
	Rem Rec (E3m3)	-
	Ult Rec (E3m3)	-
Field	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (E3m3)	0
NGL	Cum (E3m3)	0
	Rem Rec (E3m3)	0
	Ult Rec (E3m3)	0

Forecast and Indicators @ Eff Date	
Product	Oil
Forecast Start	2024-07-01
Forecast End	2056-05-01
Presentation	Unit Plots
Initial Rate (m3/d)	1.32
Final Rate (m3/d)	0.16
Ult Rec (m3)	37.65
Cum (m3)	17.56
Rem Rec (m3)	20.09
Res Life (yrs)	30.82
RLI Full Year (yrs)	6.89
Res Half Life (yrs)	3.47

CERTIFICATE OF TECHNICAL QUALIFICATONS

This report has been prepared and reviewed thoroughly by the authors to the best of their knowledge. Data and interpretations presented in this report are of the opinion of the authors and are believed accurate in nature as a function of the quality and quantity of the available data. Estimates and interpretations presented herein are considered reasonable and should be accepted with the understanding that revisions may be justified if additional data is acquired.

PERMIT TO PRACTICE
GLJ LTD.

RM Signature: [redacted]

RM APEGA ID#: 67686

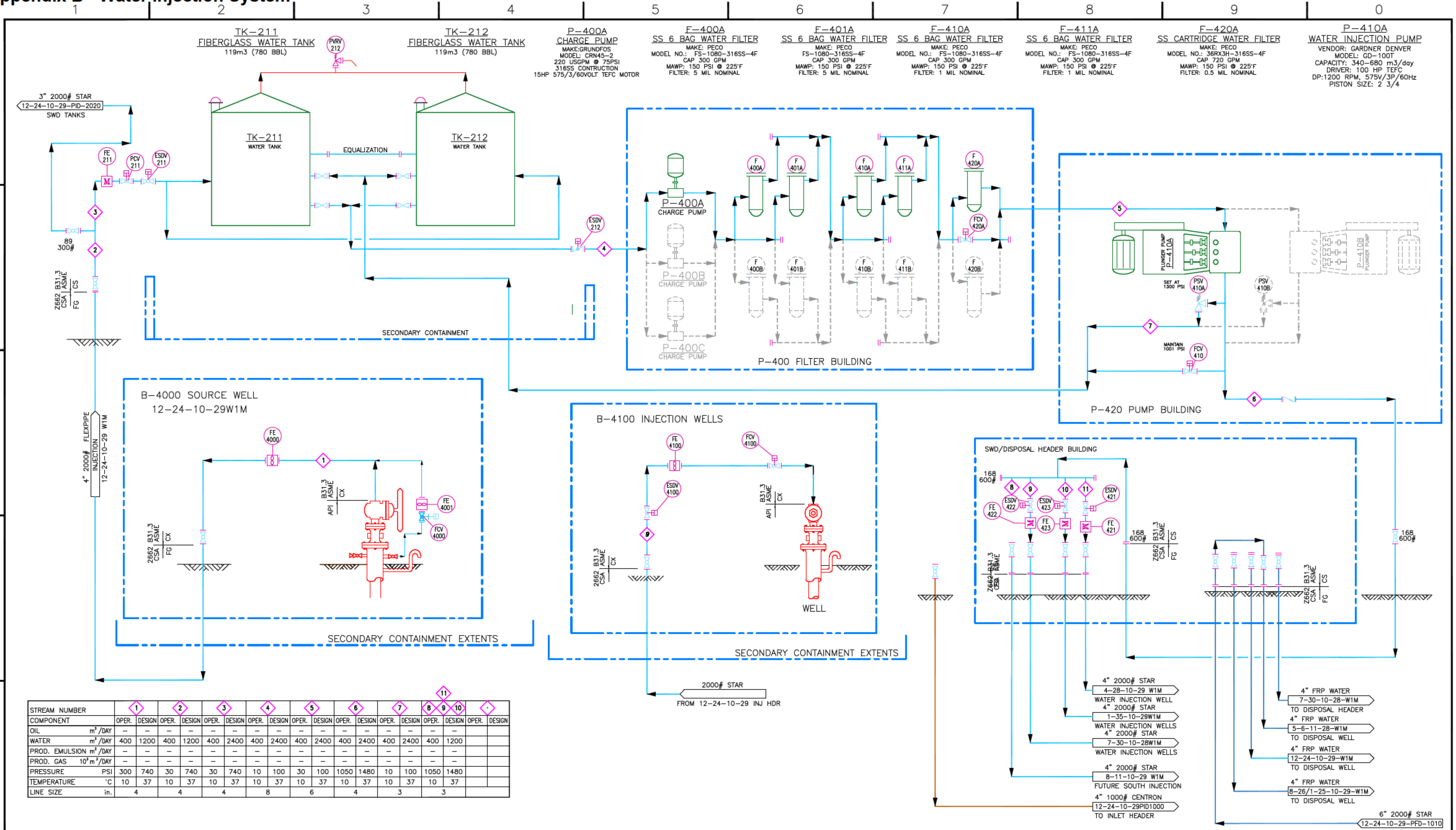
Date: October 15, 2024

PERMIT NUMBER: P 2066
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

[redacted]

[redacted] Trisha S. MacDonald, P.Eng. VP, Engineering November 15, 2024 ID#72500	[redacted] Charlene A. Maines, P. Geo. Senior Geologist November 15, 2024 ID#72789	[redacted] Warren R. Bindon, P. Geo. Senior Geologist November 15, 2024 ID#94352	[redacted] Michael Livingstone, P. Geo. VP, Geosciences November 15, 2024 ID#281178
[redacted] Nicson Do, P. Eng. Engineer November 15, 2024 ID#203471			

Appendix B - Water Injection System



STREAM NUMBER	1		2		3		4		5		6		7		8, 9, 10, 11		·	
COMPONENT	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN	OPER.	DESIGN
OIL m^3/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
WATER m^3/DAY	400	1200	400	1200	400	2400	400	2400	400	2400	400	2400	400	2400	400	1200		
PROD. EMULSION m^3/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
PROD. GAS $10^3 m^3$/DAY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		
PRESSURE PSI	300	740	30	740	30	740	10	100	30	100	1050	1480	10	100	1050	1480		
TEMPERATURE °C	10	37	10	37	10	37	10	37	10	37	10	37	10	37	10	37		
LINE SIZE in.	4		4		4		8		6		4		3		3			

REV	DESCRIPTION	BY	DATE	CHK	APP
2	NEW SOURCE WELL	SB	29JULY2024	–	–
1	SALES GAS COMPRESSOR ADDITION	JC	15MAR2021	AB	–
0	ISSUED FOR CONSTRUCTION	JC	30MAY2013	BE	–

REFERENCE DRAWING

–

NOTES:

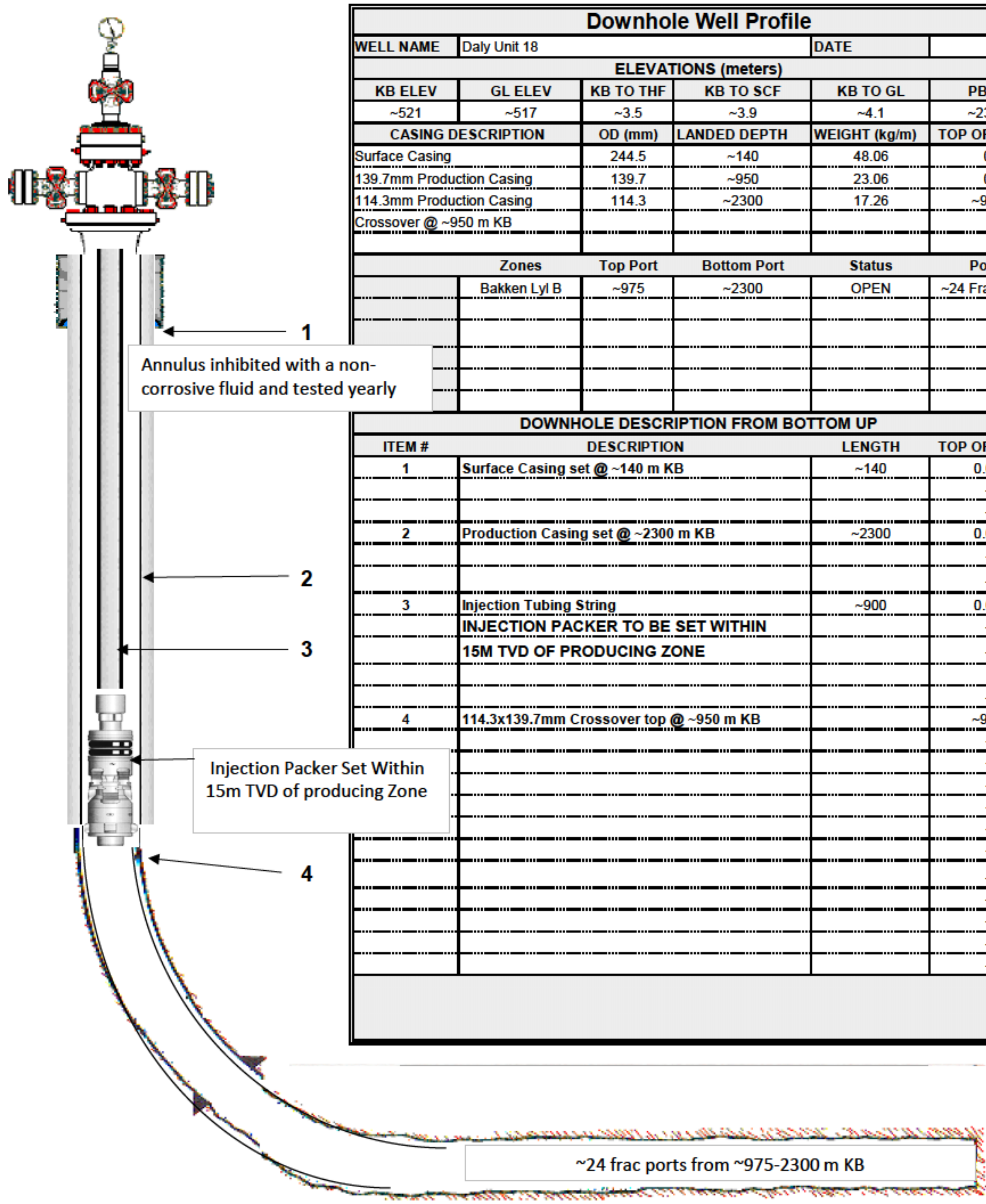
TUNDRA OIL & GAS

DALY
12-24-10-29W1M

PROCESS FLOW DIAGRAM 3 OF 4
INJECTION SYSTEM

DRAWN BY:	SCALE:	AFE:	DRAWING NUMBER:	REV NO:
RM	NTS		12-24-10-29-PFD-1010	2

Appendix C - Horizontal Injector Downhole Diagram



Downhole Well Profile

WELL NAME	Daly Unit 18	DATE	

ELEVATIONS (meters)

KB ELEV	GL ELEV	KB TO THF	KB TO SCF	KB TO GL	PBTD
~521	~517	~3.5	~3.9	~4.1	~2300

CASING DESCRIPTION	OD (mm)	LANDED DEPTH	WEIGHT (kg/m)	TOP OF (mKB)
Surface Casing	244.5	~140	48.06	0
139.7mm Production Casing	139.7	~950	23.06	0
114.3mm Production Casing	114.3	~2300	17.26	~950
Crossover @ ~950 m KB				

	Zones	Top Port	Bottom Port	Status	Ports
	Bakken Lyl B	~975	~2300	OPEN	~24 Frac Ports

DOWNHOLE DESCRIPTION FROM BOTTOM UP

ITEM #	DESCRIPTION	LENGTH	TOP OF (mKB)
1	**Surface Casing set @ ~140 m KB**	~140	0.00
			-
			-
2	**Production Casing set @ ~2300 m KB**	~2300	0.00
			-
			-
3	**Injection Tubing String**	~900	0.00
	INJECTION PACKER TO BE SET WITHIN		-
	15M TVD OF PRODUCING ZONE		-
			-
4	**114.3x139.7mm Crossover top @ ~950 m KB**		~950
			-
			-
			-
			-
			-
			-
			-
			-
			-
			-
			-

Appendix D

Daly Unit No. 18 - Representative Initial Pressure

Location	Test Date	Final Pressure (kPa)
100/07-33-010-28W1/0	Nov 2, 2012 – Nov 21, 2012	6045.0

Appendix E - Planned Corrosion Control

EOR Waterflood Project

Planned Corrosion Control Program **

Source Well

- Continuous downhole corrosion inhibition
- Continuous surface corrosion inhibitor injection
- Downhole iron control injection
- Corrosion resistant valves and internally coated surface piping

Pipelines

- High Pressure Pipeline to Daly Unit 18 injection wells – Maximum operating 1440 psi (9,920 kPa).

Injection Wellhead/Surface Piping

- Corrosion resistant valves and stainless steel and/or internally coated steel surface piping

Injection Well

- Casing cathodic protection where required
- Wetted surfaces coated downhole packer
- Corrosion inhibited water in the annulus between tubing/casing
- Internally coated tubing surface to packer
- Surface freeze protection of annular fluid
- Corrosion resistant master valve
- Corrosion resistant pipeline valve
- Injection wells with cased holes will have continuous downhole corrosion inhibition

Producing Wells

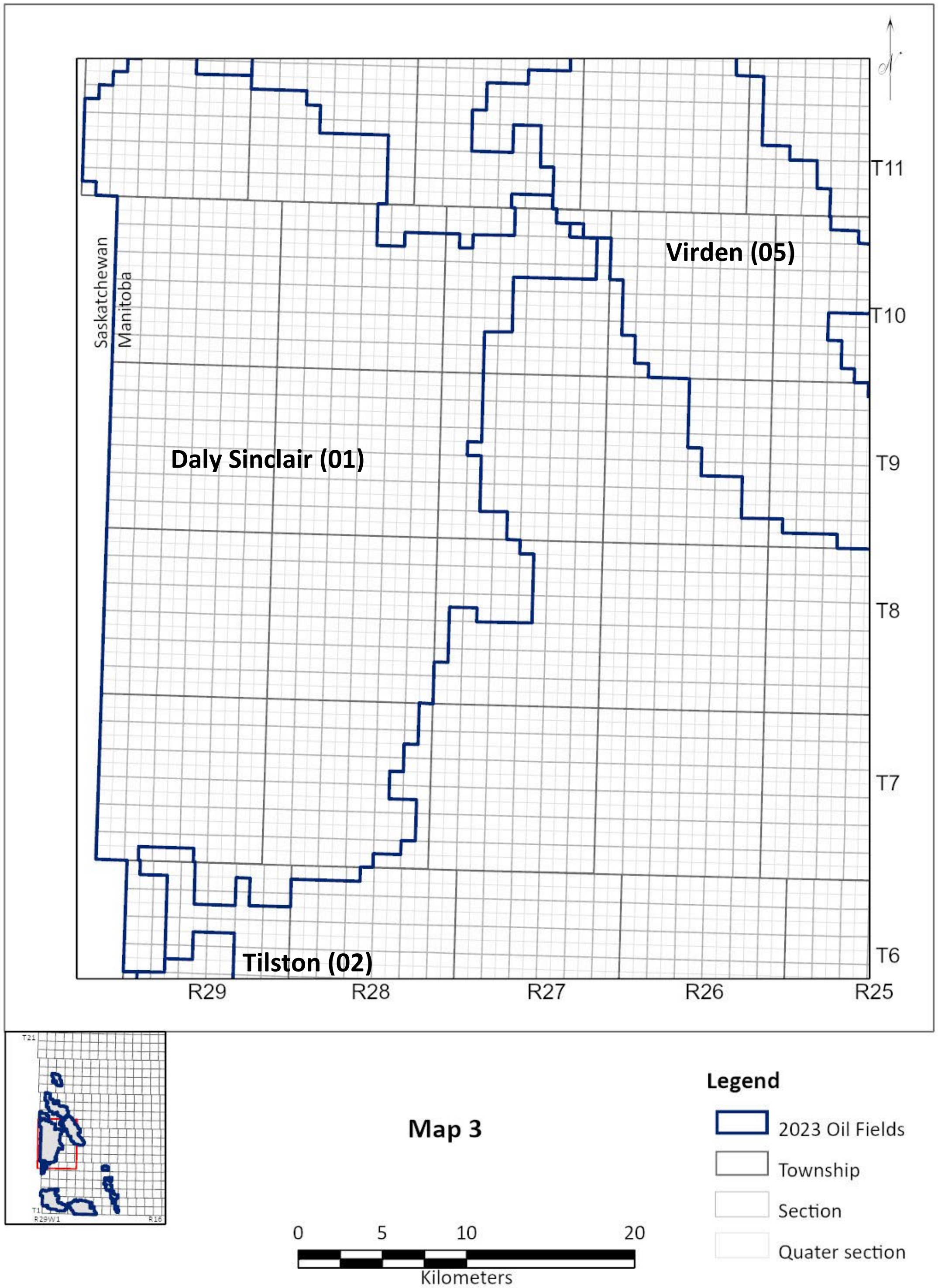
- Casing cathodic protection where required
- Downhole batch corrosion inhibition as required
- Downhole iron chelator injection as required

Proposed Daly Unit No. 18

Application for Enhanced Oil Recovery Waterflood Project

List of Maps

Map 12 - Daly Sinclair Field Boundary



Map 13 - Bakken-Torquay A Pool Map